COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

```
In the Matter of:                    )
                                     )
Preparation of the 2005 Integrated   ) Docket No.
Energy Policy Report                 ) 04-IEP-01F
                                     )
Re: Transmission - Renewables        )
    Integration Issues               )
_____________________________________)
```

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, FEBRUARY 3, 2005

9:10 A.M.

Reported by:
Christopher Loverro
Contract No. 150-04-002

COMMISSIONERS PRESENT

John Geesman, Presiding Member

James Boyd, Associate Member

Jackalyne Pfannenstiel

ADVISORS PRESENT

Melissa Jones

STAFF PRESENT

Don Kondoleon

George Simons

ALSO PRESENT

Jim Dyer
Electric Power Research Institute

Yuri Makarov
California Independent System Operator

Nick Miller
General Electric

Joe Eto
Consortium for Electric Reliability Tech Solutions
Lawrence Berkeley National Laboratory

Jorge Chacon
Southern California Edison Company

Chifong Thomas
Pacific Gas and Electric Company

Sarah Majok
Sacramento Municipal Utility District

Joseph Kloberdanz
San Diego Gas and Electric
Southern California Gas Company
Sempra Energy

ALSO PRESENT

James Caldwell
PPM Energy

Harold M. "Hal" Romanowitz
Oak Creek Energy Systems, Inc.

Nancy Rader
California Wind Energy Association

Steve Munson
Vulcan Power Company

Mauri Miller
Pazza Verde Ventures
California Wind Energy Association

Jane H. Turnbull
League of Women Voters, Los Altos/Mountain
View Area

Ellen Allman
Caithness Energy, LLC

I N D E X

INDEX

P R O C E E D I N G S

9:10 a.m.

PRESIDING MEMBER GEESMAN: I'd like to welcome everyone. This is another in a continuing series of workshops for the Energy Commission's 2005 Integrated Energy Policy Report.

I'm John Geesman, the Commission's Presiding Member of the Integrated Energy Policy Report Committee. To my left is Commissioner Jim Boyd, the Associate Member of the Integrated Energy Policy Report Committee. And to his left is Commissioner Jackie Pfannenstiel, who sits with me on the Commission's Renewables Committee. To my right is Melissa Jones, my staff assistant.

I don't have much to say in terms of an introduction other than the fact that this subject, integrating intermittent resources into our transmission grid, is quite likely the most difficult intellectual challenge that grid managers and the utility industry are likely to face over the next decade.

And we have tried to focus our resources on framing many of the questions that we've determined should be answered. In doing that we've tried to cast the net quite broadly; review the experience of others in this country and in Europe; and try to bring to bear the best knowledge available to us in addressing issues that California is going to have to confront in a very large way over the next several years.

We don't intend this effort to end here or to end in this year's Integrated Energy Policy Report. In fact, I think the best contribution we'll be able to make is to frame a larger multiyear research agenda.

So I would encourage people that address us on this topic, both today and in the future, to recognize the ongoing nature of the work. Not to expect us to be able to derive any sweeping conclusions, but really acknowledge the preference of trying to identify where we need to go next. What additional questions need to be asked; what additional answers need to be discovered.

And I would certainly ask for that same spirit of open-mindedness and inquiry from the utilities.

Commissioner Boyd.

COMMISSIONER BOYD: Thank you, Commissioner Geesman. I think you pretty well covered it all. I couldn't add much more to it other than to say that some of us have been watching this subject for a long, long time. And, as you say, it's a very complex issue.

So, I'm very much looking forward to the discussions that we have today, and how we ultimately deal with the question in the next iteration of the Integrated Energy Policy Report.

So, thank you.

PRESIDING MEMBER GEESMAN: Okay. Don.

MR. KONDOLEON: Thank you, Commissioners. My name is Don Kondoleon; I'm the Transmission Program Manager here at the Energy Commission. Again, I'd like to welcome you all here today.

Just to let you know that the concern about interconnection of renewables and the operational issues associated with that interconnection is a concern that was raised in the 2004 IEPR process.

The Committee asked staff to move forward, as Commissioner Geesman just indicated. And in that vein we have retained the services of the CERTS team. They've done some background research; they've talked to stakeholders. And they're here today to present those results.

Jim Dyer from the Electric Power Group will provide the first presentation. There is a document that has been produced. It's posted on the website and there are copies at the front desk if you haven't already picked one up.

Following that we'll have a presentation from the ISO on work that they've done; a paper that they were working on as late as yesterday, from what I understand, on the implications of interconnecting intermittence to their system.

That will be followed by a presentation from Nick Miller of GE. He will talk about the developments they've been moving forward with in the turbine field.

Finally, we'll follow up with a panel discussion. It will be facilitated by Joe Eto of Lawrence Berkeley National Lab. And we have five folks who are signed up right now to engage in a discussion of the issues that were discussed and presented by EPG. And then some additional followup questions that were attached to the initial agenda.

Folks will have an opportunity to provide comments at the end of the stakeholder discussion. And then we'll talk about the next steps.

Let me list, at this point, talk about the fact that we see the direction of this work and this workshop today focusing more in the wind area. We're talking about intermittent resources. And so we have moved forward in focusing on wind, as of today.

However, I don't want to let folks in the geothermal area feel like they're being short-changed. We are, here at a staff level, working together with our folks in the PIER renewables area. And we will be coordinating our efforts to present a workshop that will focus strictly on geothermal issues. And that workshop will take place sometime in April, probably mid to late April. And we'll make sure all of the folks here are notified about that.

So, with that, let me introduce Jim Dyer from the Electric Power Group to initiate this morning's presentations.

MR. DYER: Good morning, Commissioners, ladies and gentlemen of the audience. It's my pleasure to be here. And as Don indicated, we have been asked to do an assessment of reliability and operational issues associated with integrating renewable resources.

But first let me acknowledge the support that both Don Kondoleon from the CEC and Joe Eto from the Service Project Office have given the team during the last few months. And we appreciate their help and support.

During this briefing what I'm going to tell you as to where we are in the project, what we've accomplished, what we've done, what our findings are to date. So the briefing will be broken up into four sections.

First we'll talk about what we've reviewed; what types of reports we've look at; the shareholder input that we received; the issues or gaps that we've identified. And then take us back in history a little bit to say let's talk about the experiences we've already gone through in the last 30, 40 years. This is not the first time we've integrated new resources.

We'll then go on to try to talk about and share with you the experiences in Europe, both in Germany and Denmark.

Then we'll go into the section of the briefing about the issue list that we have.

The next portion, as far as recapping

the issues and next steps, Joe Eto, prior to the panel session, will recap the issues for the audience. And then Don Kondoleon will talk about the next steps later on.

The team at EPG did extensive search and review of numerous documents. We have a number of 38 studies and reports. I think it's much higher than that, because every time you went someplace or talked to someone, you got directed to another report, another study, another website. So there's a tremendous amount of information out there.

But the documents that we looked at were from the CEC, the CPUC, both national and international transmission system operator reports, federal and state government reports, conferences; and also very critical with the feedback from the stakeholders.

So, from all that work, all that review, we identified what we believe are some issues that need to be addressed to be successful in the implementation of integration. If we want to achieve this goal we have to be planning and develop strategies and procedures to go forward and be successful.

The gaps that we've identified are part of our issue list. And we'll go through that in a little while.

This is a list of the stakeholders that we engaged for their comment and feedback on our issue list to see if they would give us some validation, are we on mark or are we all wet. So, we looked at organizations, developers, utilities, control area operators, both municipalities and investor-owned utilities.

This is the gap issue list that we have developed based on our review of the reports and studies. There's a lot of reports and studies out there; there's a lot that's focused more on the economic analysis, the how do I cost the different products and services. But there's a gap in some areas of how do I operationalize all this stuff. How do I focus on the reliability and make sure that when we turn this stuff over to the system operator he's got the tools and policies and procedures to fully integrate it and make it a success. So this is our shopping list. And we'll go through this in detail for your benefit.

But let's go back in history, and this kind of -- I look at this chart and this reflects my 30 years of working at Southern California Edison's control center, and firsthand experience in each and every one of these issues. It brings back some fond memories.

But I think the message here is we've done this before. We've been successful. But it requires planning, coordination, practices, procedures and action.

And first of all, you look at the integration of coal. You know, we're trying to aggressively diversify the resource mix in California. We're pretty much 100 percent dependent on oil and gas to be the swing fuel. We needed a new resource. We built transmission 800 miles out to New Mexico, to Arizona, to southern Nevada to link up to the Four Corners, Navajo and Mojave projects to get fuel diversification.

Well, these things, we got the resources through dynamic scheduling. They were baseloaded resources -- and by the way, we ran into a lot of technical problems with subsynchronous resonance, which caused forced outages of two units at Mojave due to the subsynchronous resonance.

And we have these things listed at baseloaded, but believe me, if anyone can remember the first several years of operation was anything but baseloaded. These were intermittent resources.

(Laughter.)

MR. DYER: Here today, gone the next hour. I mean it was just -- it was challenging times.

At about the same time we developed Pacific Intertie, building transmission 1000, 1500 miles away from the load center, going after again exchange -- seasonal exchanges and low cost renewable hydro.

It broadened challenges, one, from reliability. You're building this long 500 kV system; new technology with series capacitors, reactors and all the dynamics associated with the new system.

Made us very dependent on reserve sharing because, you know, this is new; it may or may not work. It required significant transmission planning and coordination throughout the WECC. And then, by the way, we found out loop flow was there. And loop flow was, or has been very significant problem throughout the WECC over the last 30 years.

I can remember the Pacific Intertie being derated up to 1200 megawatts. And that is an impact on your reserves, your load carrying capability. So, there were challenges then.

When the utilities shifted from winter peaking to summer peaking it made a significant impact on our load factor. We went from a 65 percent load factor to a 55 percent load factor. And then the result of that is you wind up cycling the conventional gas-fired overnight or on a weekend. So, again, it was a change in our resource mix, more baseloaded, less flexible resources, and the conventional resources had to take the swing.

In the late 70s, early 80s we brought on the two units in Diablo Canyon, the two nuclear units at San Onofre, the three units at Palo Verde. You talk about a shock. Those things performed very well, too well. There were times when the gas-fired units sat at minimum load 18 hours a day. You just ran them up for the peak and you ran them back down and put them to bed. Because basically the rest of the load was taken care of by the nuclear resources.

So, again, the message here is we've

been through this type of thing before. With planning, coordination, policies, procedures we can do it again.

Again, dependency on system imports, the minimum load issues, bringing the QFs on in the early to mid '80s. There was 10,000 megawatts of QF thrown into the state. Most of them, because of the structure of the contracts, they were baseloaded resources. Minimum load issues, no generation control.

So the message here is we've done it before, we can do it again. We just need to plan and coordinate and be ready for it.

Let's turn to the experience that we can gain from Germany and Denmark, from E.ON Netz in Germany and Eltra in Denmark. If you look at E.ON, they have about approximately 6200 megawatts of installed wind capacity. They have a peak demand of about 19,000. And their total installed generation is approximately 35,000 megawatts.

With Eltra, they've got approximately 2400 megawatts of wind generation capacity installed. Peak demand of approximately 3800 megawatts. And total installed capacity of approximately 7500 megawatts.

If you look at the wind performance at E.ON first, the penetration in there is approximately 18 percent of installed generation; 8500 gigawatt hours wind production, which represents about 8 percent of the total energy requirement.

Looking at Eltra, much more impressive -- 32 percent of the total installed generation capacity, 4800 gigawatt hours; 23 percent of the energy requirement is met by wind generation.

So significant penetration in these two areas. By far Germany is the world leader. I think in the total country there's about 13,000 to 14,000 megawatts installed wind capacity. So, significant.

Now, they've done it. Doesn't mean that it was easy. It was a little painful. In some cases they learned the hard way. So, let's just talk a few minutes about how they have survived, what have they done differently.

There's several strategies that they utilized. One is both E.ON and Eltra are members of UCTE, which is the Union of Coordination of Transmission Electricity, which basically is the European countries which represent approximately

360,000 megawatt peak demand.

So both those companies are members of UCTE. Eltra is also a member of the Nordic Pool. Nordic Pool is approximately 54,000 megawatts of peak demand. So E.ON obtains reserve sharing and energy imbalance from UCTE; Eltra obtains reserve sharing and imbalance energy from the Nordic Pool first, and then UCTE.

So they have a strong strategy as a result of strong interconnection with the ability to share their excess energy with both the Scandinavian countries and the other countries in Europe. And when there's times when the intermittent generation is not there, they have the ability to import. So tremendous dependency on imports and exports.

Look at the issues they were challenged with. Forecast variability, forecast errors of 50 to 60 percent. Production variability, contribution to daily peak ranged from a tenth of a percent to 32 percent. Ramping, six-hour production variability 60 to 70 percent of installed capacity. Daily production variability, 4300 megawatts.

Shadow reserves. High dependency on

shadow reserves up to 80 percent of installed generation, wind generation. No grid voltage support during faults. You have a fault on the transmission system; they'd clear the fault, but with that clearing of the fault you'd lose approximately 60 percent of the wind generation. So you turn a transmission problem into a resource adequacy problem very quickly.

So the methods that have allowed them to survive consisted of generation management where through they have a process and protocol where they limit or can limit through a communication process where they can basically send out a set-point to the plans that, you know, do not produce any more because of transmission constraints, or you're above the load curve, or whatever.

The other thing is they've developed grid codes that establish performance standards for the generators. High reserves to shadow the intermittent resources. And then high dependency on interconnection. So that's the strategy that they use to manage the intermittent type resources.

Generation management, grid codes, high reserves, interconnection support.

Let's just, before we go into the issue list, just talk and remind everybody where we are and where we want to go. This is data that's provided, we got from the CEC's reports. And you've probably seen it time and time again. But it's just a sanity check to say, okay, where are we and where do we want to go.

If you look at 2002, look at the renewable resources broken into intermittent and baseload, you look at 2010, the message here is the baseload is going to increase by 50 percent; the intermittent resources are going to increase by 207 percent. Significant changes in the resource mix in the next several years. And 2010 is not that far off.

And this slide here just gives you an idea where the energy and capacity associated with the renewable resource is coming from, the different biomass, geothermal, solar and wind. And where they are potentially physically located.

So this is a scenario based on input from various stakeholders that they think these are the resources that will be there. This is the expected energy and capacity.

As we share this information with the

stakeholders we kind of asked them if they agree with this scenario, or would they modify it somewhat. For the most, the stakeholders agreed that this is a very likely scenario, but there were some stakeholders that pointed out to us that there is a high potential for large wind development in southern Nevada.

There are also individuals that wanted to make us aware that there's a high, very high potential for geothermal in Nevada that could come into north of Lugo, could come in through the DC. There is also geothermal being considered up in northern California and southern Oregon.

So, for the most part, people agree, but there is some potential modifications to this scenario.

We looked at some of the characteristics of renewable resources in their operational impacts. We put them in the two categories, intermittent and baseload. The intermittent consists of small hydro, solar and wind. And these are the characteristics. Production may not correlate with system load. And somebody say you could argue sun, the solar does. But, you know, some of our peaks in the nonsummer months, you know, the peak is an hour after sunset. So it doesn't always correlate to it.

Production forecast uncertainty. Production variability, limited ability to control output without curtailments. No regulation or ramping to follow load.

On the other side we have the baseload, which is biomass and geothermal. Around-the-clock production, limited ability to control output, no regulation or ramping to follow load.

Well, let's move into the operational and reliability issues facing California. The first one is load following, and let me first quality, we're saying load following, we mean load following the customer demand as well as intermittent generation. So it's following both of them.

What you see here in this picture is first the blue line represents the California ISO load profile from September 7, 2004. And you can see from approximately 6:00 in the morning until about 4:00 in the afternoon you have the load following requirement of approximately 22,000 megawatts. That's pretty significant. And, you know, so what are the resources that are following that.

And the green line just represents and illustrative that, you know, if you have some renewable resources that do not correlate with the system demand, to change their load profile could be additive to the customers load requirement. So the two of them can be additive, which means that instead of 22,000 megawatt requirement you could have a 26,000 megawatt requirement for load following.

The next topic is minimum load. And anyone that's operated a power system in the last two decades or so is very familiar with minimum load in California. It's been there, you know, we currently experience it. It's basically when you look at this here, this drawing just shows a seven-day profile, load profile, and resources stacked up underneath. And you can see during the minimum load periods that there's little or no room.

And that's because of the types of resources we have. We have a high dependency on coal and nuclear, which are baseloaded. We have certain run-of-the-river hydro. We have contracts, QF contracts, DWR contracts that are baseloaded and unflexible. So if you just stack them up, you say we currently have problems.

Now, if you bring on additional renewable resources that are both intermittent that like to produce a lot in the middle of the night, and baseload, you could be adding anywhere from 4000 to 5000 megawatts on top of the existing. So, we have the potential for increasing the minimum load issues in California.

And the reminder, again this is not an issue that they're bringing to the table. The issue is already there. They're just going to contribute to or compound the problem.

The next topic is storage and load shifting, and so if storage, you know, has the ability to take some of the offpeak energy through pump storage or injection into the ground of storing the energy, and then transferring it into energy, bringing back in the form of generation during the onpeak, you know, this state has approximately 4000 megawatts of pump storage.

Unfortunately, they're tied with hydro projects and downstream requirements and flood control such that in runoff time those resources are not available from pump storage.

And if you look at most of the wind production or the maximum wind production on an annual basis is in the spring runoff period. So just when you might really need these resources to help you manage the minimum load issue, they may not be available.

So the question is do we need storage as part of our strategy, who's thinking about it, whose radar screen is it on, what are we doing, who needs to take ownership of them.

Reserves. If we want adequate operating margin and a reliable system we need reserves. Reserves, both operational that are online are a quick start, or in standby. You know, the installed reserve capability includes both standby and operating reserve. And I indicated, needs to be able to come online and operate and perform rather rapidly.

In California the reserve requirement, the planning reserve target is anywhere from 15 to 70 percent. The question is what level of additional reserves might be required, or will be required to integrate renewables.

Down towards the bottom you can see this is just E.ON's experience. As I mentioned already, for 2003, the percent contribution of wind power to cover the daily peak varied from a tenth of a percent to 32 percent. And you can just look at that chart and it says, okay, they've been successful and helped a lot in some cases; other times they were not there. So what fills in the gap in the times that intermittent resources are not there.

E.ON's strategy is they maintain the traditional power stations equivalent up to 80 percent of installed wind capacity to shadow intermittent resources. They also operate with anywhere from 50 to 60 percent operating reserves to cover intermittent resources. And they come up with that number based on they've looked at the worst case of maximum change in resources in a six-hour period. And so that's their reserve requirements.

So the question is for the state, for the WECC reliability, what should the planning reserve be. Should it be modified. Is the 15 percent the right number going forward with renewable intermittent resources. And for the reliability council is the traditional 5 and 7 percent operating reserve, the right number to insure and maintain reliability of the grid.

So, this question, someone's going to take ownership; someone's got to work with WECC and the state regulatory bodies.

Load and generation forecast variability. You know, for the most part the load, you know, probably 95 percent of the year you can predict the load within, you know, 1, 1.5 percent accuracy. But there are those times when the heat wave comes in and you just get blindsided. I mean the ISO might miss the load forecast by 2000 to 2500 megawatts. That's not unusual. You get caught every year, year after year, there's always an unanticipated heat wave.

We already know that. We already have these issues. If we now have forecast errors on the resource side, at some times it will complement and mitigate the load forecast error, but sometimes they may be additive and compound the error.

So instead of, you know, a 2000, you may have a 4000 error. And so what is the strategy, what do we give the system operators, the tools, the policies, the procedures, the strategy to mitigate those things.

And as you can see on this chart here, there's only a few times in the year and a few hours or a few days that you have the issue. It doesn't mean, since it's a low probability you just ignore it, because the system operator has got to manage the problem. And we're not expecting him to manage the load on an ongoing basis. We've seen that in 2001. It's not too nice.

So, these issues are going to be there. Other countries have developed strategies. They have a lot of shadow generation. They have a lot of operating reserve. So we need to develop a strategy for the state. And so the forecast accuracy affects the reserve requirements.

So we've talked about load following; we've talked about minimum load; we've talked about reserves; we've talked about forecast errors. If we don't effectively manage those issues and develop the appropriate policies and procedures and standards to address them correctly, we've set the system operator up to fail. And he'll fail in the form of he will not meet the NERC and WECC control performance and disturbance performance standards. And that's not an acceptable option.

So, we need to solve the earlier issues such when it comes to the NERC and WECC control and disturbance performance requirements they will meet them, we will have reliable system. The control performance says each control area will do its portion to maintain the interconnection frequency. It will not transfer its problems, whether it be under-generation or over-generation, to an adjacent utility.

Disturbance control standard says if you have disturbance and loss of generation or transmission you will solve it in 15 minutes. End of report. So, we need to solve the others, the problem doesn't jump out here, and we're in noncompliance.

Frequency deviations. We always have some type of frequency, we're never right on 60 cycles. But we seldom see significant frequency deviations. We hope never to see a 96 again. But I'm sure that's what the folks back in the east interconnection thought in 2003, it'll never happen here.

You know, we've seen it. We've seen it in '82, we've seen it in '85, we've seen it in

'96, and we're going to see it again. It's probably going to happen. It just what we have is we've established some standards. Currently the WECC has standards our there that says you need to be able to ride through certain short-term frequency deviations. And so the words on the right, and the picture on the left show if you stay inside the blue lines, we can ride out most of these disturbances and keep the western interconnection intact and not impact firm load.

And we've represented in green of just maybe what a system impact would look like in staying within the standards and everything is performing well.

If we fail to have the appropriate ride through capability and so that's the question, what is the frequency ride-through capability for renewable resources. If we don't have a standard, then we need to understand what's the consequences, what's the impact on noncompliance, excessive loss of generation when we have these type of disturbances, un-coordination or lack of coordination with under-frequency load shedding and significant restoration when we do have these events.

So, what's the standard. If there is no standard, what's the consequences. Who's looking at it.

The other thing, while we talked about frequency deviation, if you look at the performance after significant events in the WECC, and this just represents what the frequency would look like. The green line represents what the system frequency would look like with appropriate and reasonable governing response from generating resources.

The red line or dashed line would be, or potentially could be what the system performance would look like with inadequate governing response. So, if you have inadequate performance the frequency is going to drop lower and stay down and could lead to cascading events.

So, again, the question is what frequency response capability should be required for renewable generation. If not, what's the consequences. Someone needs to look at it. Of course, there will be an impact.

Just as we were talking about frequency, let's talk about voltage and a voltage ride-through performance requirement. I think we're doing much better in this area. I think there's a lot going on, a lot has gone on in the last two years, significant improvement.

The WECC, FERC, AWEA, Alberta ESO, electric system operator, all have proposed ride-through standards. The WECC is a little bit more stringent than AWEA and what FERC is proposing.

AWEA, in addition to the ride-through, has proposed a power factor standard, which is again a significant support to the system. E.ON and Eltra have developed standards, grid standards.

What you see on the drawing here is a representation of -- the red line is the AWEA-proposed standard. The WECC's proposed standard includes the red line plus the blue area here. So it's a little bit more stringent. And these standards are saying at the point of interconnection the WECC says you need to withstand down to zero voltage. The AWEA says you need to withstand it down to 15 percent at the point of interconnection.

So there is a slight conflict and it does have implications. So which one will we adopt. One thing is the procurement folks that are out there procuring need to understand there are standards to make sure that they are getting these standards met. But which one is the appropriate one. And if we adopt the AWEA, what's the consequences versus the WECC.

One impact could be if you have the AWEA standard could potentially restrict the size of the collector station at Tehachapi. From the standpoint is if you have a large cluster of wind generation that can't meet the ride-through capability of WECC, then for the right event you could lose a significant amount of generation. And that would violate the reliability. So that says that you need to have a smaller collector station than the potential 4000 megawatt station they're proposing.

California controllable unit retirements. You know, we've talked about our current load following requirements. We've talked about new resources coming in that are either base loaded or intermittent. So, you know, we said that the California ISO on some days experience, you know, 20-some-odd-thousand load following requirement.

So this, the black line just shows the

load following requirement going out in time. The green line shows that because new resources coming, we're keeping up with it. But then we're potentially facing retirements and we're going to get behind the ball. The red line just shows you the change in load following capability.

So we're not putting any resources in there with the right attributes that are going to be able to follow load. So, again, the question is who's looking at, from a state strategy, from a resource mix that says all right, we need certain attributes to be brought to the table. And if we don't do something we have set the system operator up for trouble.

So, here on the far right you can see a list of the attributes that the current conventional resources have, the ones that are planned to be retired, you know, such as automatic generation control, dependable startup, dispatchability, governor response, VSS.

And so if those units are gone what generation mix do you need to bring those attributes back to the system operator.

Deliverability. The renewable resources are not going to be located right in the middle of the load center. You know, they're going to be Tehachapis, Imperial Valley, Nevada, Oregon, northern California. So, we're going to have remote resources that need to get to the load center. And most of them are proposed to be in the southern portion of California.

So if we don't want to wind up with a congestion problem that's, you know, an example of the Los Angeles basin freeways, -- anyone drives through there they know what congestion is like -- so if we want to avoid that, we need to think about how do we get these resources that are remote from load, that need to be distributed throughout the State of California, and need to be done not just at the time of peak, but all different times of the year.

So, you know, we want to capture the full benefit of these resources and we don't want to increase congestion. So, someone needs to look at deliverability other than just at the peak hour of the year.

This just kind of brings up a question. We've got approximately 18,000 megawatts of transmission coming into the state. It has served us extremely well over the many decades.

But we're not the only state that's looking at RPS. You know, the Governor of New Mexico wants 4000 megawatts of wind built there. Wyoming wants to build a lot. Everyone wants to. So everyone, I mean I think there's currently approximately seven states in the west that have developed an RPS goal and objective.

So, if you have the changing resource mix in the western United States, and also in California, what is the impact or what might be the impact on the transfer capability between all these different states.

You know, transmission, the ratings that we give transmission is based on the thermal capability, the voltage between the source and the sink, and in the middle. But it's also based on the performance of the generation that's connected to that grid.

So if you have baseload and are intermittent, no governor response type of resources, you may not be able to sustain some of these transmission rates. So, the question is, what's the impact. Who's looking at it. I mean is it WECC. No.

So, from a global standpoint we,

California needs to look at the impact of our changing resource mix, and the WECC needs to look at a global perspective, what's the implication on the WECC. The north/south transfer capability would be reduced. We don't know.

So, again, it's just kind of going for what is Californian and the rest WECC need to do to maintain the ratings of its transmission system. And, again, these are not issues that, you know, that the developers have ownership. These are the transmission owners, the control area operators have to take ownership and solve it.

Planning. Planning and modeling. And this is an issue that came up when we were talking to the folks from SMUD. And they said, you know, this hadn't been on our issue list, but they pointed out it says, you know, from a planning perspective they just look at the peak day. And they try to manage for the peak. And you say, wow, there's a whole lot of other hours besides the peak in the year, so they're only looking at the peak day; they're not looking at the peak transfer conditions, of which it may be in the middle of the night in the spring, or the fall.

So, we need to develop some case studies for the WECC that are, you know, look at other times, you know, other than peak; get some offpeak cases that represents what's really going on and see how the system performs under those conditions.

Planning models are basically defined as inadequate. We have a missing good forecast of wind production. The models do not truly represent the performance of these types of generators.

When you're bringing generation in from remote areas, they may be utilizing remedial action schemes to get them in. The question is how much RAS is enough. Should there be a standard on the use of RAS.

There was an absence of wind production data available to allow analysis. There's an absence of good weather data to help them forecast what to expect.

I've gone through 12 different issues. And, again, this is a result of our research, talking with stakeholders of potential issues that could impede or present us challenges with integrating renewable resources. We think we can overcome them. We just need to understand what the issues are, who needs to take care of them, and what timeline is going to get it resolved.

So with that, I'll conclude my presentation. And I'll pass it over to Don.

MR. KONDOLEON: Before Jim leaves let me ask the Committee, first off, if there are any questions for Jim.

PRESIDING MEMBER GEESMAN: Are we going to have a written report, Don?

MR. KONDOLEON: Yes. I can follow that up under next steps, but, yes. The process is that we'll have another workshop. We'll take the work we've done to date, we're going to be asking for comments. We'll have a workshop sometime later in April that will move this forward with regard to actually developing a policy recommendation -- options, let's put it that way -- policy options. We'll have a workshop in April to take those, again, with the audience here.

And then ultimately that will all be packaged in a report that the EPG will produce. That document will be attached to the staff transmission whitepaper that will be released probably towards the latter part of July.

PRESIDING MEMBER GEESMAN: Great. I had one question, but I also wanted to thank you, Jim, for providing, I think, an excellent survey of the landscape in front of us.

My question relates to your comments about potential limitations on what you characterized as the collector system. And taking Tehachapi, as an example, is that a problem remedied by more substations in that particular area?

MR. DYER: My understanding, and not having been involved in any of the technical studies, but if you adopt the WECC standard, it may be beyond the turbines' capability to perform. And it may -- then you're saying is, do I have to have more stations, smaller collector stations, or are there more hardware things that you can put on the developer's side of the meter to help mitigate that.

So it's one of the two.

PRESIDING MEMBER GEESMAN: Okay, thank you.

Commissioner Pfannenstiel.

COMMISSIONER PFANNENSTIEL: Jim, one question. In looking at the results of the experience in Denmark and in Germany, just as a general observation do they solve their problems by a different kind of planning, or is it just a more expensive system?

MR. DYER: They've solved some of it, you know, by developing the standards. Unfortunately, the standards were developed after all the renewables -- the wind came on.

It is expensive. E.ON and Eltra keep this shadow generation on through an RMR type process. And I think it costs them, you know, I think in 2003 it cost them in excess of 100 million Euros. And that cost is going up.

And the other question is as the other nations around them start developing more and more wind, their ability to push their excess off on them, and maybe will pick up their deficiencies from them, will be reduced.

An example is in the northern part of Germany there's a lot of offshore wind being developed. Well, that's significantly impacting Denmark's ability to export to Germany. It's just basically causing downstream congestion. So they're in the dynamic world.

The strategy that has worked for them

the last several years may not be sustainable in the future. And they need to develop new strategies.

PRESIDING MEMBER GEESMAN: What types of technologies do they use for this shadow generation?

MR. DYER: It's basically taking the conventional types of resource they have; enhancing them such that one is they can be quick-start, quick ramping, and just make sure they're there when the generator is or is not -- the intermittent generation is or is not there.

PRESIDING MEMBER GEESMAN: So, they're using existing steam plants to do that?

MR. DYER: Yes.

PRESIDING MEMBER GEESMAN: And would that be a need perhaps better met with new combustion turbines?

MR. DYER: Well, you know, the CCGTs that are currently out there are very efficient. But they're not very flexible. They don't bring all the attributes of some of the conventional; they don't have the good turndown; they don't have the good ramping capability.

So it's a sacrifice. You got good

efficient low heat rates, but you gave up some of the other attributes.

PRESIDING MEMBER GEESMAN: What about simply installing a fleet of peakers as opposed to combined cycles?

MR. DYER: Yeah, I mean that's do-able. I mean, that was a strategy for, you know, San Diego and Edison and others for many years. That's, you know, they were put in in the late '60s and they were there. You know, they ran half a percent of the time in the whole year, but they were there when you needed them.

PRESIDING MEMBER GEESMAN: Thank you.

COMMISSIONER PFANNENSTIEL: Is the European grid interconnected similar to ours? I mean closely interconnected, and so they can move around, or they have the kind of transmission constraints we have in different areas? Is that a similarity?

MR. DYER: It's a very tight grid; it's probably more like the east interconnection, the size of it, the tightness of it. You know, it's a densely populated area. And, yes, you know, every grid has its congestion. But there's a lot of flexibility and capability between them.

Going up to the Nordic Pool, that's using DC transmission; it's not as big; but, you know, Eltra is not that big, either. It's only a 3500 megawatt system.

COMMISSIONER BOYD: Getting back to the discussion of shadow generation and the discussion of peakers. We've built quite a few simple cycle peakers in the last few years. Do we have a downpayment on the matrix of peakers that could provide for the future with regard to this shadow generation that's needed?

MR. DYER: I'll defer that to somebody in the audience. I'm not sure. You know, I'm not that familiar with the types of resources that they've put on recently.

COMMISSIONER BOYD: Well, I'll leave that question for the staff to answer later.

PRESIDING MEMBER GEESMAN: All right, thank you.

MR. KONDOLEON: Thank you, Jim. The next presentation will be by Yuri Makarov from the California Independent System Operator. We have copies of his presentation.

Given the large turnout we've had today I'm not sure we have enough to cover everyone right now. We're actually in the process of reproducing additional copies of this presentation and all of the presentations from the front. I noticed all of the material is missing. I think what I will do is when we get those copies, if it's between a break in the presentations, I will ask the audience for those that have not received the material and will try to distribute it at that time. Because we don't want you to go home empty-handed.

MR. MAKAROV: Good morning, ladies and gentlemen. Today I would like to present the California ISO perspective on wind generation operating issues. And this is the kind of presentation which our operations directors wanted us to do.

We start to experience certain problems, wind energy, some initial signs of potential future problems, and we would like to share this information with you in order to make sure that we work together to solve those problems before they manifest themselves in a much more significant extent.

Today's topics are some fundamental information on the control area and its control, fundamental issues of the area control error, load following and regulation. I'm sorry I'm repeating some of the parts of the previous presentation. It was not intentional. Just because the problems are understood in the same way in different places. That's the reason.

The second topic is wind generation impacts on our balancing functions. And next we will consider some of the observations we see in our systems. And I would like to propose some possible solutions. The list is open, it's not, of course, final. And, once again, we need to work together for optimal solutions here and conclusions.

So the first topic is fundamentals of area control. And I wish I had three more hours to discuss --

(Laughter.)

MR. MAKAROV: -- those matters. I understand that I don't have the time, so let me just try to briefly describe those issues. And in case, if you have questions, you are more than welcome to ask them.

The thing which we control in real time is the area control error. Before we analyze the area control error, itself, we have to consider the schematic diagram that we have. Area 1, say it can be California ISO control area. We have a set of tielines connecting our area with the rest of interconnection. We have meters installed on most tielines. We have frequency and in steady state condition frequency is the same in all parts of the interconnection. Of course, in real time, we can have some differences because of the transient processes in the system.

And in each control area there are several things, parameters, such as net interchange, I; and this is just some of power flows in the old tielines. We have generation load and a certain parameter which is called the bias setting. This is a frequency bias setting, which actually shows how the control area responds to frequency changes.

So the area control error, which is the expression which is in the right bottom corner, is a function of the differences between the net actual interchange and the interchange schedule, which is delta I, and also it's a function of interconnection frequency.

So, our purpose is to keep this

parameter as close to zero as possible. At the same time, our objective is not to keep this parameter equal to zero all the time. First of all, it's not possible. And second, it's not economical to pursue such an objective.

And as Jim told already in the previous presentation, there are certain standards for area control error and interconnection frequency, which are established by NERC. Right now those are the kind of, I would say, recommendations. But the current process is that those requirements will be made standards, national-wide standards. So it's a much more serious thing than it is now.

And this is an additional slide which helps to understand our control objectives. So we have a kind of balance between generation and interchange. And our objective is to maintain this balance and also we want to maintain the scheduled interchanges and support of interconnection frequency.

To achieve these objective we exercise three processes. Scheduling process, day-ahead and hour-ahead process; load following process; and regulation.

This particular slide explains those

three components of those three processes. And this schematic slide simplified significantly, simplified but nevertheless helps to understand what we do.

In this diagram we have just one hour. And for this hour we have the block schedule of generation, which is the bottom part of this diagram. Obviously we have differences between the block schedule and the demand in our system. And those differences are first addressed by the load following process, which is the blue area.

So before October 1st this process was manual. The real time dispatchers were trying to balance the actual generation against load. And also a number of following ramps in our system.

Now, after October 1st, we have our market design 1B implemented. In this process we have an automatic system. Automatic system which actually consists of two programs. One of them is the security constraint unit commitment program and we show every 15 minutes. And the security constraint economic dispatch program, show on 75 minutes. And those programs are calculating the dispatches for up to two hours ahead of time for each five-minute interval.

Nevertheless, we still have differences between the actual load and generation, and those differences are instantaneous differences, minute-to-minute differences. We hour-by-hour automatic generation control system.

So the difference between the black curved line, which is the load profile, and the final real-time dispatch, they are addressed by our automatic generation control systems.

So, having said that, let's just have a quick look on the real load following regulation processes. You see they are a bit more complicated than I explained before. And the interesting -- the most interesting things here are as follows:

First of all, we have this blue line on the top, the top part of this picture. And this blue line is the actual regulation, which we call the total deviation of regulating units from the preferent point of operation. So that's called regulation.

The interesting observation about this curve is that we have some systematic longer term deviations. Say for 15, 20 minutes, this total regulation can deviate from zero. And I am stressing this point because we've had an argument. Some people say that regulation is just, you know, addresses some minute-by-minute durations of area control error. We look on this picture we instantly see that that's not exactly true.

The next thing which is important about regulation is that we have some units which are above their set point -- sorry, when I'm excited I'm speak a little bit more Russian --

(Laughter.)

MR. MAKAROV: Forgive me for that. Some units are above their reference operating point; some are below. And it may happen that the units we show above the operating -- above the set point, they actually give moved up. At the same time, the units which are below, they get moved down. It looks strange, but this is done to minimize the impact on regulating units. We don't want to force regulating units to reverse very frequently because it's a kind of varying problem for them.

So that's why the regulation process looks a little bit more complicated than it maybe could be, if we have some perfect regulating units.

So, regulation is not about only how these deviates from our real-time schedule. It's also about how we control our regulating units.

The picture in the bottom of the slide, on the left-hand side it shows a similar picture for load following. Those are so-called fixed unit. And this process is similar, but it's a different process.

This process is performed by our real-time market duplication systems which I described already. Security constraint, unit commitment and security constraints, economic dispatch.

The next topic of today's presentation is the wind generation impact on our balancing functions. I am sorry again, you know, some parts of my presentation will repeat in some extent the previous presentation. It wasn't intentional, but it's true.

First of all, that's one of the days we have with wind generation changing from about 1000 megawatts down to zero, and then going back to 800 megawatts. So, in the first part of this process we need to dispatch about 1000 megawatts of additional generation or activate our non spinning reserves. And this is a significant amount.

Say, as an example, this is La Paloma Power Plant, which is four aggregate combined-cycle facility. And when wind generation goes up, we need to decrease generation by approximately 800 megawatt using decremental bids or dispatching of the units. And 800 megawatts is the size of the Delta Energy Center Facility, which is a three-by-one combined cycle facility.

The next picture addresses the potential impact of other generators' performance. And this is quite an interesting subject. What I am trying to show here that because of the variability of wind generation we can have some sudden impacts on other generators.

And as an example I selected combined cycle facilities. Those facilities are quite strange animals, and they have some operational differences than the traditional types of units. First of all, they are designed as baseload units. They can't decrease their generation below 70 percent of their capacity because of the pollution constraints. New type of units can go up to 50 percent. But they don't have much these units in our system.

The heat rate rapidly increase when generation decrease. So, the economical aspect is also very important -- are highly efficient units. For example, the H type of General Electric combined cycle units exceed 60 percent threshold of efficiency. So but if we decrease generation, you know, the heat rate goes up.

The startup costs. They are enormous for these units, from $8000 to $50,000 for each startup. This is not just one thing, but there are some other things. They are slow starters. For a cold start, we start the process, can take up to six hours to start those units. And each start is a pain -- okay, it's a big problem because there is an -- varying problem associated with that. And having frequent startups, those units need to have more frequent maintenance.

For example, the GE-F series, which is quite frequent type of units which can be seen in the systems, will need to have maintenance after 800 startups. The maintenance is an expensive and long-time procedure.

So we can't predict them. If we start to cycle those units we can't predict them, they need maintenance. And this is one of the operational problem.

Next, in each startup process is an air pollution situation. We have more air pollution because of the startups. And the situation is quite strange. If forced to cycle combined-cycle units because of wind, you know, we are saving -- but we are using the say the green power resource, but at the same time we're forced the other units to pollute the air.

Okay, the next screen is also interesting because we just completed a comprehensive operational report on combined cycle units. And we visited many -- several combined-cycle plants in California. And some of them we are seen, we know they are all actually participating in a load following and -- most of them are participating in load following and automatic generation control.

And sometimes they complain, you know, we have false intermittent resources and they force us to more frequently, you know, change set points and move, you know, up and down over time.

The interesting thing that we expect about 16,000 megawatts of new combined-cycle capacity by the year 2015, 16,000 megawatts. And

if we have several thousand more of wind energy,
it will be quite an interesting combination.

PRESIDING MEMBER GEESMAN: You've been cycling these units, though, quite a bit for reasons completely unrelated to intermittent resources, though, haven't you?

MR. MAKAROV: Yeah. That's true. I'm not saying that all cycles are because of that. So I'm just trying to give an idea what would happen if we have more, much more combined-cycle units with the same operational characteristics and we have much more wind.

PRESIDING MEMBER GEESMAN: Is there any way to determine what proportion of your cycling is attributable to intermittent resources?

MR. MAKAROV: We didn't think about that yet. We just see potential problem here. And, of course, it's a matter of studies.

PRESIDING MEMBER GEESMAN: Sure.

MR. MAKAROV: Frequency response, I'm not going to stop on this topic for a long time because it was quite comprehensively already addressed. And this is just a diagram which shows 1770 megawatt generation treatment Western interconnection. Frequency went up to 59.75

almost. And this is the kind of relatively good frequency response. The initial response, is response from system loads, but also frequency response it can support interconnection frequency in some extent.

The second stage is because of the governor, governor response on generators, which is one of the main, I would say, main factors which supports interconnection frequency at the initial stage.

And then we have the agency control. And if you go, you know, further to the right, we have some potential human interaction that frequency stays below certain limits. So that's a kind of good situation.

But, the red line that shows what could happen if we have insufficient frequency response from the governors and frequency can go below, up to 59.4 Hertz. And if frequency stays there three minutes or more, the generator starts to trip. And then the generator start to trip, we have some further frequency changes in the negative direction. So if frequency reaches 57 Hertz those trips are instantaneous. There is no delay there. So it's quite an unpleasant situation which actually looks like a system collapse.

Also, at 59.1 Hertz the load shedding begins. And load shedding is the kind of emergency control measure, because if you shed the load we increase the interconnection frequency. So frequency response is important.

And there are some NERC policies. Policy 1 says that generators should be fully responsive to frequency deviations exceeding plus/minus 0.036 Hertz. And it also says that generators about 10 megawatts or greater should have speed governors. It's not a standard. I would say it's a kind of recommendation right now. But it's a, I would say, meaningful recommendation.

We observe frequency response deteriorating, especially this situation is observed in eastern interconnection. But we also have certain problems related to that.

Okay, I'm running out of time.

(Laughter.)

MR. MAKAROV: Okay, I'll try to finish my presentation in five minutes. Okay. The -- impacts on our system is the reduced transfer capability on the California/Oregon Intertie, and slow frequency recovery.

The next one shows the load curve against wind generation curve, and this slide was addressed already or a similar slide.

The next is the over-generation problem. It shows that the maximum wind generation production is in April, May and June. We have some July, as well. In April, May we have, you know, must-take generation from our hydropower plants. So we have an over-generation situation there.

Ramp rates. This matter was addressed already. We can pass the ramp rates.

Intermittency at high wind speeds. It's one of the factors which concerns us, because, you know, we see this green line which is Solano County generation, and we have a sudden reduction of generation of 150 to almost 50, and then generation went back. It looks like the situation when we have high wind speeds. And those changes are very sharp.

Summary of considerations. I'm not going to stay on that. Just repeat all things which I just addressed before.

And the last part of my presentation is

related to some possible solutions for the discussion. We think that wind generation resources should be equipped with day-ahead and hour-ahead forecasting service for better scheduling process.

We also need to equipped with meteorological towers and provide real-time telemetry to the California ISO for near-real-time forecasting purposes.

We need to have information, capacity derate information coming to the California ISO systems.

We need to improve the quality of real-time information; it's a big, big problem.

We need to develop displays, alert systems and near-real time forecasting systems.

Dispatchability. This matter was addressed already a little bit. So I'm just repeating the same thing. We need to have a certain degree of dispatchability of wind generation resources.

One of the successful experiences in the past was an intermittent resources workgroup which was very successful in developing our PIRP program, participating intermittent resources program. One of the ideas which we could discuss is to create a second group to discuss operational issues, rather than market integration issues.

New technologies. I'm not a specialist here, but the improved unit design energy storage systems, we, of course, need to use, as much as possible, European experience and possibly some other technologies.

And the final question is should we think about harmonization of the California generation portfolio in the future. Should we think about a mix of generation which could make our system operational and reliable.

Conclusions. We are committed to achieve the goals of the California renewable portfolio standard. We notice certain operational issues and want to address them ahead of time.

And we need to work together to pave the road for much more green power in California.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Yuri.

MR. WRIGHT: Thank you, sir.

MR. KONDOLEON: Any questions from the Committee? None. Thanks, Yuri.

Okay, before I call Nick Miller up to speak for General Electric, we did make additional copies of all of the presentations. I'm going to have Jim put those back at the back table so that if you're missing anything that was handed out previously, please take the opportunity to retrieve your copy.

And with that, let me introduce Nick Miller.

MR. MILLER: Mr. Chairman, everyone, thank you. I'll see if I can get us back on track. A lot of some of the points that I was going to make have been made this morning and I'll talk from the perspective -- I've got to wear several hats this morning.

I'm a power system engineer, transmission planner by expertise, not originally a wind guy. And I have been very heavily involved with GE's entry into the wind generation business at a time that is incredibly exciting. And we're wrestling now with some of the results of the success of the industry.

So, with that, I'll go ahead, taking a step back from California's needs to look at systemic needs around the world. We heard from the concerns in Germany, Eltra, Spain and I can add to that other places around the world, Hydro Quebec, Brazil, many other places are wrestling with this question of how to build on the success of bringing wind generation into the system to progressively higher and higher levels.

There's was mention of the offshore projects in Europe, UK, which is about a 50 gigawatt system, and is a physical and electrical island, are talking about offshore projects that are measures in the multiple gigawatts. And these questions of grid integration and intermittency are very much in the forefront.

This slide here sort of shows you from GE's perspective, not surprisingly as a GE Energy is not just a supplier of wind turbines, we do lots of stuff, and we want to take care of our industry in a holistic sense. And the solution to enabling high penetration of renewables, particularly wind, is, in our view, a combination of technologies.

And you see on this slide -- I'll zero in on a couple of points. There's a multiplicity of timeframes. I'm going to dig down. Yuri's and Dave Hawkins' work showed that very nicely in some of their papers. We have re-found or refined those points in the New York work, which I'll talk about briefly as we go through here.

But there's different time scales associated with dealing with the intermittency, and we believe that in broad terms -- I don't think anybody in this room would disagree -- that there's a spectrum of solutions that include doing the absolute best in forecasting; taking advantage of storage; taking the very best advantage of all the available controls and developing new functionality within wind turbines; and linking them up with technology of alternative types of resources, not necessarily renewables.

So this is sort of a holistic picture that goes from slow on the left to fast on the right.

I'll give you a quick high-level view here of some of the big chunks, and none of this will be surprising to you in the room. And I won't talk too much about hydro storage. It seems clear that hydro is naturally a good complement to wind generation. There needs to be some evolution, particularly in this part of the country, to drive additional storage and to do other things from a technology point of view. The only thing I'll point out is that certainly one of the things on the radar as equipment manufacturer is this point of variable speed pumping. Remember that pumped hydro is generally not finely controllable when it's pumping. It's either the watts are going up, or they aren't going up. And in order to deal with the variability that Yuri talked about so well, having the ability to finely control the pumping megawatts, as well as the generating megawatts, appears to have significant systemic and commercial value.

I'm going to drill into actual controls at the wind turbine and windfarm level as we go down, so skip over that slide for the moment.

But to your question about combustion turbines, we've been wrestling with that problem, as well. GE makes combustion turbines. We have a new generation that I've been very excited about, and we're actually doing work looking at hybridizing with wind generation, maybe a piece of the puzzle.

The next generation of relatively small gas turbines that in GE-speak are LMS-100s. They are a hybrid between so-called aero-derivative gas turbines, the kinds that you're accustomed to seeing stuck on the wing of an airplane, and frame-type machines that, for example, have the pedigree that Yuri talked about, F-frames, into relatively large -- these are 100 megawatt class machines -- that have several of the characteristics that you would like to see for firming for wind.

That is they start and stop quickly and cheaply. They maneuver up and down very fast. Simple cycle. They have an amazingly high heat rate for simple cycle combustion turbines, 10 points higher than anything else you can buy right at the moment, which is not 10 percent incremental, but 10 points higher.

And they have good heat rate down to -- fired back. And you see some numbers on there. So we're trying to figure out exactly how that fits in the picture with the storming questions, but it seems obvious to us that that is one of the pieces of the puzzle, just one.

And then several points were made about forecasting. I'm not a forecasting expert, but clearly better information in every timeframe built into the market is one of the ways to deal with the intermittency and variability of wind. It isn't a completely wild animal; it is reasonably predictable. And our policies need to go forward on that basis.

Okay, quick just view of the technology, and I won't spend time on this, just to get everybody calibrated. All of my talk here is about GE turbines. This discussion does translate to other manufacturers' stuff, but I'll be GE-centric here, if you don't mind.

These 1.5 megawatts are sort of our workhorse; getting close to 3000 of these installed. They come in different sizes on the mechanical side, but have basically very similar electrical characteristics, which I'm going to talk about.

And then these are the big guys for offshore. We don't actually see this being a big player in the California energy mix for the moment, but. This is (inaudible); these guys are really big. The swept area for that wind turbine is almost a hectare. Blades are, wing span is 104 meters. Can fit a 747 in the shadow of that wind, with quite a bit of room left over. So this is a farm off the coast of Ireland. It's up and doing its thing at the moment.

Okay, a quick high-level view of these time scales because it's easy to get balled up in the differences between all the different operational challenges. And if you haven't lived in this world, as many people in the room have, the variability drives different pieces of the challenge, each of which fit together.

So in the broad term, looking to posture the system for day-ahead, recognizing that your GE combined cycle plants need six hours to start, you got to get your unit commitment right the day ahead. Can't do that without good forecasting, getting the right mix.

That is not the same problem as wrestling with following the load as it comes up in the morning or going down in the afternoon. Short-term forecasting, clever tricks with managing the megawatt output of the windfarm, mixing with resources like those new generation of gas turbines are probably the right combination solution.

And then we get down to the very fast stuff. Yuri put up some nice slides on AGC. When we're talking about response in the fractions of seconds, or ones of maybe tens of seconds, ones of minutes, we have a lot of untapped margin still to deal with some of those variabilities right at the wind turbine, right at the windfarm level.

This slide is going to be preaching to the converted just a little bit, but it's useful to put the scale of the problem and the technology things in the context of system needs and requirements. And what you got here is a slide that goes sort of from left to right and bottom to top in terms of single windfarms, ones where wind turbines just need to exhibit healthy behavior for the local behavior of the system, right. They aren't going to move the grid around.

As you go to bigger windfarms and lots of windfarms, well, this whole meaning here is talking about driving needs to this side of the spectrum. How do you get the whole grid to work. We go to progressively higher levels of requirements.

And I've got four columns here to talk about general classes of technology. Protection; this is under/over frequency trip-out. This is making sure that when wind turbines are islanded from the rest of the grid they don't do unpleasant things.

The desire to have low-voltage ride-through is, to some extent, hostile to the desire to make sure that wind turbines get offline when you inadvertently create an island. Those are some technology questions that still haven't been wrestled to the ground.

I'll show you, in terms of managing reactive power, keeping the voltage healthy, keeping the grid stable, most of those issues, from our perspective, are already well addressed.

And the big thing over here, as we move up the spectrum of difficulty, is to handle the megawatt output of wind turbines in progressively more creative and aggressive fashions.

So I'm going to work through some of these. The color-coding here is basically the blue stuff is off-the-shelf; you can get it today; your developers get it today. The green stuff is imminent or possibly even available, but not built. And the red stuff is what we're working on. Again, this is a GE-centric view. We are in front of the curve, but we like to be there.

Okay, shopping list, zeroing in on the relatively short timeframe. We've got a bunch of different technology issues in terms of keeping the grid healthy. You heard most of these today so I'm going to zoom in on a couple of examples.

It is worth noting that there's a little bit of a mixture of technology questions that are associated with the physical location of wind generation that are somewhat independent of the fact that it's wind. And the fact that wind behaves differently.

And from a policy and where-do-you-drive-the-state point of view, there's no particular need to separate that, except a the conceptual level. The reality is that these windfarms tend to be out in the middle of nowhere. I'm sure all of my GE colleagues that live up in Tehachapi would agree.

(Laughter.)

MR. MILLER: Anyway. So I'm going to give two quick illustrations of how far we've come in the last year or so, and then talk a little, very quickly, about where we're going. And then make several comments that actually aren't in my talk, but were set up for me by the previous speaker.

So, we've got two big farms that have

been commissioned in the last year or so that are illustrative of where we have taken the technology and give you a little bit of insight on where it's going.

So, two big farms in WECC, Taiban Mesa, New Mexico Wind Energy Center. I'm always corrected by Public Service New Mexico. Taiban Mesa is the name of the substation. Which is out here on the New Mexico/Texas border. This is a long skinny radial 345 line. It's a big farm. New Mexico is only about a 1600 megawatt system. So a single farm with 200 megawatts is enough to really shake the system. And they are really on the steep part of the learning curve. So in terms of learning lessons, California can watch some of the things that are going on in New Mexico to see what works and what doesn't.

And then the other one is this Colorado Green farm, which, again, happens to be out on the end of an extension cord; this time 230 kV feeding into Excel Public Service of Colorado.

So let's talk about these two things. Taiban Mesa -- actually I need to go back to the drawing, excuse me. Because Public Service New Mexico is only a 1600 megawatt system, when they started doing system engineering one of the planners called me up. This is about 18 months ago now. He said, hey, Nick, every time there's a fault on the 345 grid anywhere in the State of New Mexico this windfarm's going to trip, is that right? The answer was, yep, that's the way we build them. And his answer was, this is not good.

(Laughter.)

MR. MILLER: What are we going to do about it? All right, so if I do brag a little bit, in an incredibly short period of time GE launched into a new development project for the first low voltage ride-through with US, and in the space of six months from "we can't live with this" to starting to build the wind turbines, we developed this low voltage ride-through.

This is a factor test showing the low voltage ride-through. That little notch in the middle of the voltage is a three-phase fault, collapsing the voltage to about 30 percent for about six cycles. That's primary clearing. You see the power. You can't push power through a fault. The power goes down close to zero and then it comes back.

So, this is the real McCoy. This has

gone out in the field. We had a few birthing pains, but they've had lots of faults in Public Service New Mexico, once we got the kinks out, and this works. This is not as aggressive as the low voltage ride-through curve that was put up before me. This is the AWEA, and again you all saw that, so I won't spend much time on it, other than to point out that I guess I hear, but I've heard conflicting things, whether or not the WECC standard really just fills that little trapezoid in down at the bottom, or whether it's more open-ended. So I'd be interested to hear the latest on that.

At least one generation of it basically read you won't trip, period, without any time constraints. We were a little excited about that, because it puts all the onus on the supplier of the equipment, and we didn't like that. So, if it is a fact that this notch is being filled in by the WECC standard, that is essentially consistent with the wind turbines that GE will be delivering to Hydro Quebec.

Which Quebec, you may have heard, just placed a gigawatt order on GE for wind turbines on the Gasp, Peninsula. And they will all have something that, at least at the first approximation, looks like this. There's a couple of asterisks next to it, so we still need to talk.

So, we're moving in that direction. As far as we're concerned, the low voltage ride-through question is largely resolved.

Colorado Green is another piece of the puzzle, again which we're sort of proud of. I guess I'm personally proud of, because I did a bunch of work on the control system. But it's also germane to California.

Colorado Green is at the end of an extension cord to which we added another extension cord. So this is the point where it connects to the utility. They built 45 miles of dedicated 230 kV transmission line farther out in the boondocks, and put 162 megawatts of wind turbines. It's a very weak system, short-circuit ratio was 3.5, if anybody wants to think of it in those terms.

The requirement for the interconnect was to regulate voltage 45 miles away at the point of interconnection. And this farm does that. And these are measurements taken last spring at the farm. And what I want to point out to you is that this blue line here is the voltage at the point of interconnection, and the blue line down here is the megawatts. This is about an hour of sample; you see the variability that Yuri showed.

I don't actually expect anybody to be able to see the scale on this; just want you to see that one of those tics is a kilovolt on a 230 kV basis. So the FIR on this guy is about 200 volts. That voltage is flat; there is no flicker. End of discussion. Pretty cool.

Okay, another question that's related to these long-distance and weak interconnections, and this come back to my point about part of this being a question of connection, part of it being a question of technology. Is that in many regards wind generation is grid friendly. I bristle a little bit at the notion that it's always disruptive compared to the nice stuff that you're accustomed to connecting to the grid. And this is a couple wiggles to show that.

And the key thing I'd like to point out really, I don't need to drag you through the whole simulation here, is this is a comparison of two topologically identical systems, one with the GE windfarm, one with the GE gas turbine. Good high tech, state of the art, synchronous machine, subject to a whack, system fall.

The red trace is the gas turbine. You see it swings around and you see there's a little hiccup in the voltage recovery. That is typical transient stability response of a generator out on a weak system.

The black curve is the dynamic response of the windfarm; voltage comes back; machine doesn't swing; it's stable as a rock. And indeed, if you whack it hard enough, the gas turbine loses synchronism, the windfarm doesn't.

On weak, stringy systems these windfarms are better mannered, not worse. Which is sort of cool, too.

I'm not going to talk about wind forecasting; that's not my expertise. I think the previous speakers made a good case already that forecasting is a key piece of the puzzle here.

A couple technology points, but I think I'm really going to go to the conclusions and make one or two additional points that aren't in my slides that I think are germane to this audience.

In my career in power this is the fastest changing technology that I've ever come close to encounter. The wind turbines and windfarms that GE is building today are radically different and much better mannered from a grid-integration point of view than they were just two years ago.

We aren't alone, but I'm here talking as GE. We are spending lots of money to put in lots of engineering to get these technology questions down, because they're an essential piece of the puzzle for our business success. We aren't just being nice guys. We want to sell more wind turbines.

A lot of the historical perspectives on wind generation are outdated. I didn't hear anything that was outdated today, so I'm not impugning any of the previous speakers. But the notion that they cause flicker, and they can't be relied to stay online, they're going to trip at the first sneeze and all that other stuff, that's water under the bridge.

We're looking at the next frontier, which is the reason for this room to be here, which is managing active power, coordinating with other resources and getting that right. And, quite honestly, we aren't quite done, we aren't close to done with that.

But there was a few things that I didn't talk about here, that I would like to put out. I'm one of the principals on the New York State integration study. I noticed in Jim's writeup you referenced the preliminary results. We're shipping the final for public review out today. And it will probably be posted on the New York DPS website. We have a stakeholders review a week from today. So it's a pity about the timing, because I could have given you a quick rundown on the New York study.

But basically there's a couple lessons learned. Many of the same things you've heard we found in New York. A lot of these numbers and concerns are scary, all right. Looks like, oh, my god, the system is really going to be shaken down. We did all that work in the context of the existing variability of load and other disturbances within New York State, and overlaid the wind.

It's very hazardous to walk away with a view of, gee, wind moves this much, it's going to disturb things. The perspective that we ended up with was the system moves this much all the time, and wind adds to that in some fashion. And is the system sufficiently resilient to handle that incremental change.

Looking at wind in isolation as though the rest of the power system is determinate and well mannered and flat isn't right. And I'm not accusing anybody in this room of doing that, but it's an easy trap to fall into when you see these megawatts moving all over the place.

We found, being as quantitatively precise as we had data and ability to do, in all those timeframes that I laid out in that earlier slide, that New York State was surprisingly resilient. And our basic conclusion was that without any significant changes in practice or additional resources, New York could handle over 3000 megawatts of new wind generation on the system. That's about 35 gigawatts.

Very encouraging result. I'm not saying that translates to California. Your system is different. But nevertheless.

There was a comment about frequency ride-through. I didn't even put that up on here, but the wind turbines that we're selling are compliant with the WECC frequency ride-through.

The modeling question, you need good

models. We are busting our ass on that, and working very very hard on it, as users in this room that anybody that's a member of WECC have access to software that has good models in it. We're working really hard to keep those up to date.

And we're wrestling real hard right now with the high wind speed drop-out point that Yuri had in one of his slides. All right. Remember, everybody, right, if the wind picks up wind turbines generate more and more power up to a certain point. And then as the wind picks up beyond that, they generate the same amount of power. So at high wind speeds the output is very flat, not variable. That takes a little bit of getting your head around it, if you're not used to looking at it.

Up to some violent wind level, at which point the wind turbines will take themselves out of service to protect themselves. That doesn't, right now the industry practice is, well, that happens. And then when the wind drops down you pick up and go on your way and you get those notches.

We believe that some relatively

straightforward control and sensing can see that those events are coming. Back the power down in a fashion so it doesn't capture everybody by surprise. Tell the system operators that that's coming, and they can posture the system. And then you can slow down the rate that they come back with fairly straightforward controls.

There's a lot of that kind of stuff going on, but I wanted to address the high wind (inaudible), because that was -- Yuri had such a beautiful plot on that.

Okay, I almost got done on time. Thank you.

MR. KONDOLEON: Does the Committee have any questions for Nick while he's here?

PRESIDING MEMBER GEESMAN: Just one. Do you have a sense of what your installed capacity within California is now?

MR. MILLER: I don't know.

PRESIDING MEMBER GEESMAN: It would strike me that despite your disclaimer, I think a lot of the conclusions that we have drawn here, based on both our current experience and our accumulated experience, based on equipment, that in large part is 10, sometimes 20 years old, and

I'm not certain how representative that equipment is, particularly listening to your presentation, what we're likely to see going forward.

We still have some institutional and market bottlenecks or roadblocks to repowering many of those sites. But hopefully we can work through that, and modernize our fleet.

I take it that your answer to many of these problems such as ramp rates, are better control technologies?

MR. MILLER: I do not believe that that's the only answer. I think sort of that pattern that I laid out at the beginning I believe in. I don't think you can get everywhere that you need to go at the level of penetration that California is looking to achieve simply by being smarter with the wind turbines.

But I do believe quite strongly that it's a part of the puzzle, and that we do need to be quantitatively -- I'm not going to -- first of all, I'm not all that expert on the way your market works or what some of these institutional roadblocks are, so I'm not going to stick my head in the middle of those.

But the notion that what we see in New

York, for example, that 3000 megawatts, looking out a day ahead, an hour ahead, and New York has got a five-minute economic dispatch, okay. So they sit there, there's market participants that are out there getting goosed around.

And we concluded that there was actually plenty of load following capability in this state to handle these; even these conditions in the place where the operators loose sleep -- not put words in Yuri's mouth and correct me -- you know, things like the morning load rise, when the wind is rolling off. All of a sudden the state is looking at following several thousand megawatts an hour at the same time that the wind is rolling off. Is there enough resource available to follow that. And we concluded yes.

If there isn't, clever controls of the wind turbines aren't going to fix that. I do not believe that.

But some of the other history with California with the many different generations of wind turbines that are in some of the places that were developed first, there's been all sorts of heartache related to managing the voltage and the VARS and who's tripping whom, you know, voltage collapse on the feeders out.

I mean there's no substitute for good system engineering. And I think a lot of those problems are a combination of old technology, a certain amount of institutional entitlement that went with those earlier generations, where they weren't being held to a standard of performance; that you should, in my view, hold new development to. And those problems are going to go away.

PRESIDING MEMBER GEESMAN: Thank you.

MR. MILLER: Um-hum.

COMMISSIONER PFANNENSTIEL: John. One question.

You mentioned the New York study thought or concluded that you could add 3000 megawatts of wind? Was that the correct number?

MR. MILLER: At least, I believe, was --

COMMISSIONER PFANNENSTIEL: And what percentage would that be of the system?

MR. MILLER: That's 10 percent of the peak load.

COMMISSIONER PFANNENSTIEL: Peak.

MR. MILLER: We agonized over what to per-unitize it on, as opposed to installed capacity. You noticed, we looked at the Germans, right. You know, it's the Germans and many of the European systems have mind-boggling amounts of capacity, installed capacity reserve. So we don't want to put it on that basis.

The other thing that, again, for the group to consider, is we went to some pains to develop a method for New York State to use to assign capacity credit for wind generation. And, you know, that's a hot button for lots of folks.

We stuck our oar in the water and the number works out for onshore, with the wind profiles that we expected in New York, to be in the neighborhood of about 15 percent of nameplate. It varies a little bit. The offshore one do much better. Some of the sites were higher, some were lower. We recommended some methodology for New York State to assign credit and to track it.

But basically wind is not a great capacity resource, no matter how you slice it.

COMMISSIONER PFANNENSTIEL: Thank you.

MR. MILLER: Okay, thanks.

MR. KONDOLEON: Thank you, Nick. We're going to move on to our panel discussion. I'll ask Joe Eto to come to the microphone. Joe's from Lawrence Berkeley National Lab. And I'll also ask the participants in the panel to please take seats around the dais. And I'll also ask you to introduce yourselves to the Committee and the audience once you've been seated. Thank you.

(Pause.)

MR. ETO: Thank you. My name is Joe Eto. I've been asked to moderate this panel. But I've also been made aware by Don Kondoleon that there are a number of members of the audience that also wish to speak to these issues. And we want to make sure that we allot enough time for that to take place this morning.

And so what I'd like to do is ask for a show of hands of the folks that would also like to speak to the set of questions that we're putting to this panel. And I'll apportion the time between the panel and the audience, based on the number who indicate an interest in speaking.

So, could I get a show of hands of how many people from the audience, who are not on the panel, would like to speak to the issues that are put before this panel session?

One, two, three, four, five, six, seven. Okay, so there's seven from the audience, and we have five panelists. That's 12 people who wish to speak. I'd like to respect the time limits that we've been given, and so what I'm going to do is ask each of the speakers, at least initially, to limit their comments to about three to four minutes. And specifically we're asking the panelists and the audience to do this, to respond to the list of questions that are on the agenda.

Namely, what we've heard this morning is a presentation from Jim Dyer and his team about the issues that they have identified through doing their homework, essentially talking to stakeholders, reading the literature and trying to narrow and sharpen the issues that need to get addressed in the next phase of this work.

And so what we're asking the panel and the audience to speak to are the questions of whether this is the right list of issues to focus on. We've put up that list of issues here. I'm not going to go through them.

We want to understand whether we've characterized the questions that we need to address in trying to address these issues accurately.

We want to make sure that the list is complete, so to the extent that there are other issues that are not on here that folks feel that are appropriately addressed in this venue, we want those to be identified.

And then finally, in terms of next steps, which we propose to be essentially to try to begin working with these issues, to develop some options for addressing them, be they from the technology, from the market, or from the regulatory side, to begin putting into this forum for more public discussion.

As Don indicated, there will be another workshop in April and where the results of that development process will be reported to you. So before we launch into that process, this is the check-in and an opportunity for the panelists, many of whom which we've spoken to, to speak to these issues, as well as to those in the audience.

If, within the time, and I know it's very short, at least in this initial go-round, you have available you are also invited within that period to speak to some of these additional questions that are on the last page of the handout. That has to do with the resource mix changing in California in terms of the types of gas-fired generation we're likely to see.

Speaks to the question of who was responsible and what processes they ought to use to try to begin to address these resource mix issues from the standpoint of these ancillary service requirements.

Also are interested in understanding to what extent what additional steps, or what steps are needed to insure that California can reap the full benefits of the renewable resources that will be connected to the grid.

And finally, what should California and others in WECC do to try to maintain the path ratings that may be affected as a result of the introduction of these renewable resources.

So, with that, I'm going to go into the panel session. And I'd like to first invite Mr. Jorge Chacon from Southern California Edison to speak to these questions.

MR. CHACON: Thank you very much. I'm here on behalf of Pat Arons, who was scheduled to be here, but she had to go and testify at the PUC. So, my name is George Chacon, I also answer to Jorge. I am a transmission planner for Southern California Edison. Been doing planning for the Company for about seven years. I've also had a small stint with a small consulting firm for about two years.

My major role in our planning department is to perform the analytical studies necessary to interconnect generation. And it doesn't really matter what type of generation, but because of the fact that I've been doing a lot of wind-related studies, when a wind study comes to Edison it usually lands on my desk. So I've got a number of those studies that are ongoing.

Based on the studies that I've been performing to date, I look at the list of issues that have been identified and I think it's fairly complete. I think the discussion that transpired today fairly much captures the issues that we're faced with.

Certainly when you're planning the network and trying to figure out what upgrades are necessary to meet the reliability standards, it becomes difficult when the technology is changing. But as Nick Miller indicated, the newer GE turbines, which is the bulk of the turbines that are being proposed into Edison, do perform a lot better. And they are -- the model's a lot more adequate to make determinations.

With that I think the only major comment that I have is really an addition, Commissioner Geesman, to your question regarding the limitation of the Tehachapi collector system. I guess you had asked if more substations would resolve the problem.

Realistically in the studies that I'm doing, what I'm seeing is that if you whack the system fairly good, it doesn't matter how many substations you have on a local collector network, the impacts propagate if the collector network is very tightly integrated.

So, having six substations or ten substations, the impacts are going to look about the same.

Realistically I think the better approach is, you know, the curve of the low voltage ride-through capability, filling in the notch on the bottom, I think, will get the performance that we're all looking at.

Based on the analysis that I'm doing, and every system is different, so it depends on the system that the generator's integrating to, but based on the analysis that I'm doing, I'm seeing that voltage at the terminal, at the generator terminal, of .15 per unit, 15 percent, would allow a ride-through even if you have a three-phase to ground buss fault on the local Tehachapi network.

So your interconnection point voltage can go to zero and still ride through, based on the current locations where the wind is coming.

Now, I must say, I haven't done the analytical work for the major Tehachapi area. That's coming up next; it's on my list of things to do. But I think the number's going to be fairly close to about 15 percent. Maybe it's 12, maybe it's 17, I'll have that number when I do the analysis.

PRESIDING MEMBER GEESMAN: When do you expect that to be finished?

MR. CHACON: I think I can have the first set of runs done in about a month. Unfortunately, because of the confidentiality agreements it's going to be delivered to the ISO and to the client. And if the client wishes to deliver it out to the world, that's their prerogative.

PRESIDING MEMBER GEESMAN: Understand. Understand. Thank you very much.

MR. CHACON: Thank you.

MR. ETO: Does the Committee have any other questions for Mr. Chacon?

PRESIDING MEMBER GEESMAN: Just wondering how we could get you more staff.

(Laughter.)

MR. ETO: Okay, let's move on to Pacific Gas and Electric and Ms. Chifong Thomas, please.

MS. THOMAS: Hi. I'm Chifong Thomas; I'm from Pacific Gas and Electric. I've been planning transmission system for a lot longer than George.

(Laughter.)

MS. THOMAS: And maybe longer than I care to admit. Anyway, I worked -- right now what I'm doing is my duty is looking at a lot more of the 500 and 230 kV type of bulk system network. And I also chair the technical studies subcommittee at WECC, although my term is going to be over shortly.

Looking at the -- I agree with George, looking at the list of issues is rather complete. One of the main concern that we have is that is identification of all the problems when we do system studies. It's only through identifying all the problems, doesn't matter who caused them, that we can devise solutions to them.

Another issue, of course, is that Jim Dyer touch on earlier is how much remedial action scheme can we have without really causing a problem where the cure would be worse than the disease.

So, anyway, so I look forward to seeing the report and contributing to the effort. And I think that certainly with enough efforts and study work the problem can be solved.

PRESIDING MEMBER GEESMAN: Let me ask you to put on your prognosticator's cap. If Congress passes mandatory reliability legislation how many of these WECC standards are likely to become compulsory?

MS. THOMAS: Probably all of them would be, but right now they are -- WECC has a reliability management system where a lot of the members has sign on voluntarily where we'll be sanctioned if we don't meet standards.

And I believe that actually after the blackout in the northeast in 2003 I'm sure that a lot of these standard would be more and more mandatory. Even though it has a voluntary flavor.

PRESIDING MEMBER GEESMAN: Okay, thank you.

MR. ETO: Are there any other questions from the Committee?

All right, let's move on to Sacramento Municipal Utility District with Ms. Sarah Majok.

MS. MAJOK: Good morning. My name is Sarah Majok; I'm with the Sacramento Municipal Utility District. I'm a transmission planner there.

As a couple of other people have said, I'm not very familiar with wind; this is new to me. I'm hoping that having a fresh pair of eyes look at this will mean that we'll see some things that maybe other people have known about and taken for granted.

Looking at the list I'm especially pleased that the transmission planning and modeling issues were added on here, because that's what I look at, as a transmission planner. And those are the issues that I deal with on a daily basis.

And now that wind is coming, we have to see what we can do to integrate it properly in our existing system.

Going through Jim Dyer's presentation, I'd like to say that SMUD, in terms of load following and reserves and resource adequacy, we have a pump storage facility that we're planning to probably come online about 2013. We currently have an existing 15 megawatt windfarm that we're looking to expand to about 100 megawatts within the next year and a half or so. So that pump storage is going to help us a lot with a lot of these issues listed here.

Also, I agree with Chifong on the RAS issue Jim was asking, and my response, or actually my question back is how much is too much, how much RAS is too much.

Looking into the future I think that with all these different issues on the table, I see this as an opportunity for new technologies to be developed to help with the integration of wind.

PRESIDING MEMBER GEESMAN: How large is your planned pump storage unit?

MS. MAJOK: 400 megawatts.

PRESIDING MEMBER GEESMAN: And where would that be located?

MS. MAJOK: At our existing Upper American River projects.

PRESIDING MEMBER GEESMAN: Thank you.

MR. ETO: Any other questions for Ms. Majok? Okay. Let's ask Mr. Jim Caldwell from PPM Energy next.

MR. CALDWELL: Good morning. My answers to the question is the list of issues valid, yes. Have the issues been accurately characterized, I'm not sure. I don't think so at this point, but I believe we could.

Are there issues or potential issues not been captured on the list, I can't think of any, but I'm certainly open to somebody. I haven't heard any this morning that should be added.

The fourth, is the study headed in the right direction and adequately focused. I'm afraid that what we're doing is, you know, that integration studies, I think, are meant to, you know, mesh two things together. And picking up on something that Nick Miller said, what we're looking at is something like the fist, and then trying to match the wind to that. And I think we need to focus much more on the system holistically and not focus and obsess on the fact about the wind.

And we need to look at the integration

of two systems that are moving around, not just one system that's static and the other system that's trying to be fit into it.

Let me go back to when I said no, that I didn't think the issue's been accurately characterized. And I'll pick up on some of the issues I heard this morning.

E.ON experience, I guess I'm sort of -- I haven't been to E.ON, myself. I read the same report that Jim Balance did to come up with those issues. I was a little bit puzzled by some of the conclusions. I've made a couple of telephone calls and actually, as luck has it, I'm going to be in E.ON, a meeting with them on the 14th of February, try to find out.

And I think something's been lost in translation. When they talk about shadow reserves what they're really talking about is this capacity factor of wind. And so 20 percent capacity factor is about what it is, which leads you to this sort of 80 percent shadow reserves.

It certainly doesn't translate into operating reserves. There's nobody that I'm aware of anywhere in the world that carries those kinds of operating reserves for wind. You can look at

Denmark, you can look at Spain, both of which have three to four times the penetration that E.ON does. And they don't carry anywhere near that kind of operating reserves. So I think something got lost in the translation.

As to the California minimum load issues, I think those are very real. I also think that those are contractual issues, and that those are policy issues, not so much physical issues. I see no reason why it would not be okay to back down on coal from Arizona or New Mexico in the middle of the night.

I see no reason to believe that, you know, we would want to extent DWR contracts past their life where we're burning $7 gas in the middle of the night, and then selling it at a $50 loss up to the northwest.

So it's sort of strange that we're saying that ah, gee, this is a problem that we can't bring in this new stuff when, you know, we're living with the mistakes of some things we have in the past, and there's going to be plenty of room if we just think about this a little holistically.

As to the WECC low voltage ride-through

standard, I'd point out that there is no WECC low voltage ride-through standard currently. There is a proposal from the reliability subcommittee within WECC to adopt a standard. That standard has significant opposition within WECC. Not so much from wind developers, although clearly we're going to cast our vote no, but many of the conventional generation operators are also going to cast their vote no. Because they can't meet that standard, either, and they see no apparent reliability benefit from having done so.

So I think it's a little early to characterize that WECC low voltage ride-through as a standard.

PRESIDING MEMBER GEESMAN: Yeah, on that subject I think Mr. Dyer's presentation identified an AWEA FERC standard in juxtaposition to the WECC standard.

MR. CALDWELL: AWEA proposed last year, seeing all this coming and seeing the desirability of in Nick Miller's thing, and Nick was part of that work, and I was, too, to come up with the AWEA proposal, that it was becoming upon the wind industry to recognize that it had an obligation to do this. And to propose, you know, to accelerate the adoption of these standards.

I mean it's in our interests to see these standards adopted. To see good standards adopted, not just something that's, you know, is taken off the wall and see whether it sticks or not.

But it was in our interest that we wanted to open that dialogue. And we did. And the result was a FERC NOPR. NOPR stands for notice of proposed rulemaking. That doesn't mean that there is a FERC standard. There is a notice of proposed rulemaking from the FERC, which relates to their interconnection standards order 2003A.

There is also a NERC SARS process. I can't remember exactly what SARS stands for, standards -- does anybody, I don't --

UNIDENTIFIED SPEAKER: (inaudible).

MR. CALDWELL: Right. There's a NERC SARS process that is kicked off on this subject. The first meeting of the NERC SARS Committee, I believe, is in San Antonio next month, in March. So, there's a lot of work going on in this area.

And, you know, I think what George is saying, that, you know, when he looks at it, that, you know, .15 is probably about right. I think that's why E.ON ended up with that standard. I think that's why most people around have ended up with that standard.

And so I think that's probably where we will end up. And I think what we'll find is that there will be certain circumstances where some sort of, that isn't good enough, because of some strange circumstances on the grid. And there we need to go to some sort of a zero voltage ride-through standard, and that'll be some sort of an add-on package that people can offer for extra money for specific circumstances.

But as a general rule, if you look at the experience around the world with about the 40 gigs of wind that's on the system around the world in Spain, Germany and everywhere else, everybody's pretty much settled on the .15 per unit as the general standard. And then special circumstances that require something else, well, then you go lower and add on cost.

There's also another NERC effort that's going on right now that I think is going to be interesting to point out. And that's a rewrite of the CPS standards that Yuri talked about, the CPS-

1 and -2. And there's a committee in NERC that's rewriting those standards.

And they're going to be more time differentiated. And I think what they're trying to say is that setting these standards for, you know, 24/7, 8760 hours out of the year, probably ends up, you know, under-setting the standards under certain hours, you know, they're not stringent enough; and then for the 8740 hours where it probably doesn't matter all that much, the standards are too strict.

And so what they're trying to do is to do time differentiated CPS standards that relate reliability to when it is at risk and when it is not. So that we can get both cheaper reliability and more reliability by focusing on when the issues are, not, you know, on the 8760.

And that same theme, I think, runs through all of these here, too. And part of that, and getting back to something that Nick Miller was talking about, about controls on turbines. That controls on turbines to take care of the rare event, the 500 year storm that comes through and makes those ramp rates go really crazy, makes a lot of sense.

It doesn't make sense to carry, you know, 80 percent reserve margin for 8760 hours out of the year when you know it hasn't rained in, you know, those storms haven't come through California, except in January of February, for the last, I don't know, 10,000 years.

And so time differentiating and getting smarter has a lot of dimensions beyond just the control schemes and just everything else. It's designing the things to happen when they need to happen. We have that ability now, I think we'll be fine.

One final comment, Nick talked about the capacity credit of wind in New York. I would just remind this Commission that they've had a big proceeding on this same thing that used essentially the same methodology on California. And clearly California wins (inaudible) better than New York wins, because the same methodology or similar methodology. It came to 15, 18 percent in New York; came up with like 22 to 25 percent in California.

And that was on a lot of old technology. And if you looked at the new technology, I think the capacity accreditation or the capacity valuation of wind in California is going to be in the high 20s. And that's consistent with what, again, what's being found on a worldwide basis.

Thank you.

PRESIDING MEMBER GEESMAN: That's not the only area that we consider ourselves superior to New York in.

(Laughter.)

MR. CALDWELL: Words per megawatt is something that we do very well at.

PRESIDING MEMBER GEESMAN: You know, Mr. Caldwell, I would appreciate it if after your visit to E.ON you do feel that there were aspects of the earlier presentation that mischaracterized their experience, if you would file something with us in writing that we could docket and then utilize.

MR. CALDWELL: I'll be happy to show you my travel photos.

(Laughter.)

MR. ETO: Are there other questions for Mr. Caldwell?

All right, let's move to the audience. Now, on my list I have Mr. Kloberdanz speaking as part of this panel. So do you want to start out.

From San Diego Gas and Electric.

MR. KLOBERDANZ: Thank you, Joe. It's perhaps my misunderstanding whether I should be on the panel or a public speaker. Regardless, I didn't want to pretend to be of the caliber of engineering capability of my colleagues on the panel, because I'm not an engineer.

I am Joe Kloberdanz; I'm with San Diego Gas and Electric. And, good morning, Commissioners.

SDG&E, I was not able to bring with me a technical expert with the credentials of my fellow panelists here today, through no fault of their own. But I want to assure you of a few things.

First of all, this issue is very important to SDG&E. Among other things, we expect significant renewable resources to come from the Imperial Valley area adjacent to our service area.

Among other things, we need to plan transmission to be able to reach those resources. And doing so will likely be critical to SDG&E meeting the 20 percent renewables goal by 2010. And we expect to meet that goal.

The state may set further goals beyond the 20 percent level. We expect to do our level best to achieve that, if that occurs. We're talking about a 500 kV line, for example.

In addition, within SDG&E's service area we are aware of the potential for at least several hundred megawatts of wind generation. So it's very important to us.

Be assured that our technical folks were among those interviewed, and I appreciate Mr. Dyer's process for inclusion there. I think that was a good idea to interview a number of the stakeholders, the way it was done, to develop the background paper.

Our technical experts have also reviewed that background paper, and have assured me that they consider the list to be essentially correct, adequate.

The one thing that was mentioned has been touched on by Mr. Miller just a little while ago, the impact of renewables on the power quality or harmonic injection or flicker issue. And Mr. Miller contends that that's essentially gone away. I would just ask that we kind of assure ourselves in this process that it, in fact, is no longer an issue. If Mr. Miller's correct, that would be great news. The IEEE standards 519 and 1453, I understand, are what's applicable here.

Lastly, I would just mention that, as Mr. Caldwell has just brought up, there is a FERC NOPR on interconnection for wind energy and other alternative technologies. I don't know how far along that is. I believe it's in the opening comment process. And all I would suggest here is that we make sure that what we do here is coordinated in whatever way is appropriate with that effort, so that we don't get cross-wise in California, unless we've got a real good reason to be cross-wise.

PRESIDING MEMBER GEESMAN: That's a significant priority that we have, and that we have communicated to the FERC Staff.

MR. KLOBERDANZ: That concludes my comments. Thank you very much.

PRESIDING MEMBER GEESMAN: Thank you, Joe.

MR. ETO: Are there other questions for Mr. Kloberdanz?

All right. I did not memorize, and I certainly don't know all the people who raised their hands, but I would like to go from left to right. And I think --

MR. ROMANOWITZ: Yeah, Hal Romanowitz.

MR. ETO: Okay. Why don't you introduce yourself to the panel and to the Committee, and then offer your remarks.

MR. ROMANOWITZ: Hi, I'm Hal Romanowitz, and I'm President of Oak Creek Energy in Tehachapi. I'm also President of the Kern Wind Energy Association. And there's been an awful -- also I'm on the Tehachapi study group with actually Jim, George and Chifong, so we've had a lot of very good interaction and a lot of progress being made.

There have been a lot of points made. I don't want to reiterate a lot of these, some very good things. And I want to hit some main points, and then a couple that I think are missing.

First, there is an excellent book directly on subject here just out, "Wind Power and Power Systems" by Wiley, ISBN# 0-470-8550808. Thomas Ackerman, the editor. And it does have a chapter on Tehachapi.

The focus of this study, I think, should be more like Jim Caldwell has suggested, rather than sort of the way that it is currently focused. It should be a holistic integration of wind as one piece of the system, not how does wind come in and fix all the other problems of the system and make the system whole.

And I think that's a critical and essential difference. And there are a couple of examples of the sorts of things of why that is important.

Like, for example, there was a discussion that there's 36,000 megawatts of new gas-fired combined-cycle generation coming that is far less flexible than it was before. That's certainly creating a much greater issue to the system than the sort of wind that we're talking about.

I understand that Calpine, for example, had an accident on one of their combined cycle units starting up recently; and the fix on that was to shave the blades a bit. And what that did is that, I believe, significantly increased the ramp rate.

So these are design differences, and wind shouldn't be out here fixing, you know, the design choices of other technologies.

Secondly, I will say this is a, you know, it's a not-settled issue, but the sort of thing integration in the system. You take where I think opportunities are probably being missed, this is not an established fact, it needs to be studied. But if you take a Helms, for example, 1200 megawatts of pumped storage, and you recognize that Helms crosses the Big Creek Corridor, the Helms lines into Greg cross the Big Creek Corridor, if you can interconnect there with phase shifters or whatever, if this can be done, this gives you a low cost transmission path parallel with Path 26 and Path 15.

And it means that the operation of Helms has to be changed. There are issues in the Big Creek Corridor. Can they be adapted. We don't know. But these are the things that really need to be studied because this may be a $500-, $600-, $700-million benefit with the existing technology. And so it needs to be studied seriously. Whether it works or not, I can't say. But these are the things that need very serious study and evaluation.

And the other thing is that storage, for example, in Tehachapi our company has looked seriously at trying to do storage. We had a 500 megawatt and three 90 megawatt pump storage projects sort of in the pipeline that we've dropped off just because there really is not a way to get them to market. It's just not -- the market doesn't work.

And it's a market issue rather than a technology issue. That basically, you know, time shifting by storage is paid for in energy. The transmission substitute function that storage would provide is paid for in transmission rates. And the ancillary services are paid for by Cal-ISO.

You got three different places, totally different. There's no coordination, no way for a facility to tap those markets that we could find. And there is other storage technology that is basically available as long as there were -- that's probably better than pump storage. And it just is a creation of a commercial opportunity for it. I don't think much else is needed.

And that most of the storage is that there is a time or there's a mismatch between storage capability and wind project capability such that integration, as has been suggested, between wind and storage on a project-by-project basis is not a very good way to do it with some of the technology out there. There's some other that might be able to do it that way, but like pump storage does not integrate well on a project-by-project basis unless you take another step like Nick Miller had suggested with variable speed storage.

And I want to close by saying that I think the cooperative working group approach has been extremely successful in Tehachapi in trying to get all of the wind that's coming along there to market. We've had, you know, significant cooperative processes, both with -- amongst many of the people here, with the military and that sort of thing, and the work where it is more than just a single workshop, but where there's an interactive process that works on a consistent basis and addresses the issues that need to be solved.

That there are normally good solutions to these things, and you can get through on a factual basis. And surprisingly enough, the industry developers, the suppliers and the IOUs have been able to find a way to work together very effectively when you get down and you find that you have to talk about real facts and that sort of thing. And surprisingly you come to solutions.

So, I'd suggest that that's probably something that's needed, sort of like Yuri has suggested, that could help this process.

PRESIDING MEMBER GEESMAN: Hal, in terms of looking at storage projects, that you'd indicated that you guys have done, if there were anything that you could share with us in writing that would quantify the impacts of that fractionated market for storage attributes, that would be helpful to us.

I'm not asking you to do new work, but if you have anything that you've previously done that you do feel you could share with our docket, it would be helpful.

MR. ROMANOWITZ: I'd be glad to do that. I might not get into the full detail you'd like to see, but I think we can focus it fairly well. And we are, you know, continuing to look at this. So we think it's something that's of real merit.

PRESIDING MEMBER GEESMAN: Thank you.

MR. ETO: All right. George in the back.

May I proactively ask the speakers to be respectful of about three minutes, at least initially, in an effort to allow everyone to have a chance to speak before the noon hour.

MR. SIMONS: I'll try to be very quick. I'm George Simons; I'm with the PIER program here at the Commission.

I wanted to follow up on a couple of comments made by the Commissioners, relative to one translating the results from Europe to California. And secondly, when we look at California specifically.

I think it's going to be very important when we look at E.ON Netz, the German system, that we look at it within the context of the larger European system. The analogy here is that we have a very deep stack in California. We have to look beyond -- and one of the reasons that's very important is that gives us the capability right now to integrate wind.

When we look at the European experience they don't rely just on what is the German reserve; they rely on the deeper European reserve, the Nordic reserve.

We need to look at the depth of the stack as well as the characteristics of the stack. The importance of that again is that I don't think we need to look at a one-to-one relationship between peakers and resolving the intermittency issue. I think there's going to be the capability within the stack to meet this if we have dynamic control response.

And that really brings us to the question of do we look at intermittent resources, or do we look at grids. And I think we have to look at grids. We have to look at California's capability to be a dynamic grid in the future.

Again, we have to become more sophisticated in how we dispatch, how we control things. I think Yuri's comments about AGC are right on target. And that's where we're going with the Cal-ISO.

I also wanted to make the point that scheduling, right now one of the things that we see when we start talking about the impact of intermittent resources on California is right now the scheduling error, itself, is typically around 2000 megawatts, but can be as large as 5000 megawatts.

So that tells us, that gives us a sense that again, we have some issues that need to be addressed within California. And if we look at

E.ON Netz and how they've handled that, perhaps we can learn how to reduce that scheduling error.

PRESIDING MEMBER GEESMAN: How much of that would you attribute to wind?

MR. SIMONS: The scheduling error is independent of wind. The scheduling error is just how the system operates.

I also wanted to talk a little bit about, so that's translating the E.ON Netz work to California. I think we need to be very careful to draw correct analogies.

When we look specifically at California, and again this is where this study is going, I want to remind the audience and the Commissioners that, in fact, the work that Nick Miller, GE did at New York, we're beginning here in California.

Nick is part of the team that we have under contract to go ahead and look at modeling out the system, not just simply looking at, for example, how would you look statically at the system, but from a dynamic perspective. What dispatch is needed.

So production cost modeling, power flow modeling is going to be introduced into that study. We expect to have some preliminary -- we hope to have preliminary results from that study some time in the fall of this year.

And I would encourage the utilities, both the public and the investor-owned utilities, to participate in that effort. I think it's going to be a very important that not only do we have data that everybody agrees this is high quality data, but also that we have expectations that fit in with respect to what would the utilities like to see as we head out to 2010.

I don't worry so much about a WECC standard, I worry about what are the needs of the utilities, and can we fashion that study to meet those needs. Because that's what we're going to have to do by the 2010 timeframe.

My last comment is we are part of WECC. And one of the things that really concerns me is that when we start talking about the capability to import generation from the WECC states, is that WECC, itself, has no capability right now to do the type of modeling studies that are necessary. So somebody has to come to the plate at WECC with resources to be able to match the types of modeling that we're going to be doing here in California.

Thank you.

MR. ETO: Questions from the Committee for Mr. Simons?

Okay. Nancy. Please introduce yourself and your affiliation.

MS. RADER: Good morning, my name is Nancy Rader with the California Wind Energy Association.

I jotted down a few thoughts when I read the report yesterday. And a lot more information came out today. So, you know, take it in that context. I'll try to link them to the comments today.

First I wanted to second Jim Caldwell's comments, which were right on point I thought. I thought the list of identified issues was almost too vague to evaluate because they're just too vague; there's no discussion of what methods are going to be used to study the issues; there's no real specific description of what, in fact, the issues are that we're going to be looking at. What methodologies and so forth.

I also thought, as Jim mentioned, that many of the questions and statements in the report inappropriately suggest or insinuate that wind or renewables are going to cause problems in the system that are really broader, larger system problems. And those problems shouldn't be pegged to wind.

For example, you know, the statement will plant retirements affect the ability to meet the load following and ramping requirements. Well, the RPS integration cost study showed that wind really doesn't change very fast. It doesn't really have a big load following -- doesn't impose a big load following burden. It changes much more slowly than other kinds of resources like block schedule generation in the State Water Project.

So the issue of plant retirements is not an issue that has to do with wind. It has to do with the overall system requirements. And so I worry about those issues being folded into this report because it tends to suggest that these issues are caused by wind, when in fact there are broader problems that maybe deserve to be placed somewhere else than in a renewables integration report. Although clearly they are a component of that.

I think it's important to identify and separate out the issues that are being addressed and being addressed well in other forms like WECC and the FERC, and to not fold those in here and revisit them and second-guess them. We need to identify the issues that are not being addressed elsewhere.

The other thing that struck me, it seemed that there was something of a disconnect between this project and the Energy Commission's RPS integration cost studies. Those studies have shown that the integration costs of our current wind capacity are trivial. And the study authors are now in the process of looking out to the scenario under when we meet the 20 percent RPS requirement.

And in talking to them I think their expectation is that the regulation costs will not change significantly, they might even go down. And the capacity values will hold steady.

So, that suggests that wind can be successfully integrated into the system at low cost. So, if that's the case, I'm wondering what is the problem.

Yeah, there is adjustments that may need to be made in the system, but I think we have to keep it in perspective. Because we read this report and look at all the graphs, you tend to sometimes think that the sky is falling. When, in fact, in the perspective of what are the costs of these issues, they're relatively small.

Likewise, you know, questions like should energy storage be required for intermittent energy additions, if wind, as these RPS studies are showing, can be integrated at low or no cost, why is storage necessary.

So I would encourage a closer dialogue perhaps between these two groups, because I'm sort of seeing a mismatch in the emphasis and the statement of the problem.

You know, that's not to say that there aren't a lot of changes that could be made, and we should be looking at how we optimize integration of wind into the system, but I think the issues have to be more specifically identified.

For example, I think we could look at what are the ancillary service costs and benefits of connecting Tehachapi south and north versus south only. It would be useful to know that and I don't think we have good information on that now.

What transmission upgrades should be attributed to renewables, specifically in RPS versus the general system needs. This is a big debate we're having in the transmission bid proceeding, where again we feel that transmission upgrades are sort of being loaded onto renewables back instead of looking at the system more broadly.

I think there are a variety of institutional barriers that should be looked at. For example, you know, the ISO right now tends to see problems that reflect past history. For example, they have a problem knowing where the wind is going because the utilities aren't participating in the forecasting program. So I think we should look at do we need the utilities to participate in that program so that the ISO an get more comfortable in handling big amounts of wind.

Another institutional barrier, I think, is that we can't get good data out of the ISO. The RPS integration cost team has been working for two years to try to get good quality data from the ISO to do robust studies, so we can't better quantify some of these costs. But it still is unable to get the kind of data that it needs.

So we'll have more written comments, but those are sort of off the top of our head.

PRESIDING MEMBER GEESMAN: Thank you, Nancy.

MR. ETO: Are there questions --

COMMISSIONER BOYD: A comment, if I might. I bit my tongue when Mr. Romanowitz spoke, but I thought he very eloquently put the point of you can't expect wind to solve all these other problems. And I thought that was the first speaker of the day who put it that way instead of the fact that the wind creates problems or exacerbates, some are willing to admit, exacerbates existing problems.

But Ms. Rader's comments about maybe being a little sensitive to that issue does make the point well, that that, indeed, is an issue.

And I guess I want to say also that Mr. Caldwell said it and Mr. Romanowitz said it, also. Looking at the whole system, I agree a hundred percent that, and have long felt you've got to look at the whole system. I just hope we have the human capability here to do that.

But it is definitely needed if we're going to plug this in and not treat it as some kind of an increment. So, I certainly am amenable to seeing what we can do to analyze the whole system and see this is as just a component rather than just a plug-in module that seems to make problems for some people.

So, anyway, just wanted to make that comment.

MR. ETO: Let's go around the room. I'm not sure who was raising their hand. Let's ask this gentleman here.

MR. MUNSON: My name is Steve Munson. I'm the CEO of Vulcan Power. And I would like to thank the staff and the Commissioners for the upcoming geothermal meeting as a follow-on to this.

I would like to make a few comments, though, about resource mix as we see it. Maybe that's kind of a precursor to the next meeting. This is not meant in any way to have a hot water company pour cold water on a wind meeting.

(Laughter.)

MR. MUNSON: But, we would ask that as you do your planning going forward that you might bear in mind the possibility that the first Tehachapi upgrade is made, but perhaps the second one is more costly. For that, and maybe other reasons, isn't the right way to go.

We have a lot of talk about 4000 megawatts of wind, and it kind of makes the geothermal guys shudder a little bit to hear about that.

I would like to summarize some responses to the excellent CERTS work this morning. This is really a good, we thought, a good start on solving some problems. It was focused on wind, and I think there were some perhaps misunderstandings advanced in terms of the way this market might look going forward.

One point made was that the majority of RPS renewables are located in southern California. That's not right. I don't believe that's right. We are in numerous meetings with geothermal companies, wind companies and biomass companies. It doesn't look to us like it's good policy, because were baseload companies, but it also might not be the best policy for the wind to have intermittence grow 207 percent and have baseload only grow 50 percent.

And in terms of the way technology might develop to service California, we actually think something that looks quite different from the charts that were presented. We think of perhaps 700 megawatts of annual average wind out of Tehachapi, which is roughly phase one line development.

There are a number of new wind projects announced and other ones in contract process. Maybe 300 megawatts average annual of wind in northern California. And at least a couple hundred megawatts of average annual wind in adjacent states that could come in here. A total of maybe 1200 megawatts average annual of wind.

We're aware of our own projects and others, and perhaps 350 megawatts of geothermal coming out of the Imperial Valley, providing some of the brine problems are solved down there. And those companies will have to deal with that. One of the brine plants was closed just three months ago. So, we hope that there could be 300 megawatts of geothermal out of the Imperial.

There's as much as 850 megawatts of geothermal in Nevada, some of it very close to the border. We have properties that are six miles from the border. 850 megawatts of geothermal in northern Nevada could service California.

There are existing transmission paths;

there are some paths that cost nothing. There are next-stage upgrades that are very cost effective. There are upgrades beyond that that roughly would cost about the same as wind. And then there's some upgrades that are interesting in that they might get in a large-scale basis on the Pacific DC intertie and bring 500 megawatts in at a cost of $100 million. That's an average cost per megawatt that's cheaper than Tehachapi I.

So there are options available to supply perhaps 850 megawatts over a five- or eight-year ramp-up from Nevada; 400 megawatts more in northern California. Calpine has a project up there; at least two other companies have projects in northern California, 400 megawatts is probably on the low side.

Another 240 megawatts from the volcano in Oregon near the border that has the highest temperature steam well, shallow steam well, in North America, 500 degrees, 240 megawatts.

All total there's 2000 megawatts or so of high quality baseload geothermal projects that could serve California. We kind of lose track, I think, all of us that there might be as many as 360 megawatts of biomass projects, as well. These projects would be serviced by the forest-thinning dollars as we try to reduce fire risks and chip trees and cut small trees and increase the health of the forests.

So I think we're kind of losing track of 360 megawatts or so of potential baseload.

So we ask, as this process goes forward, that we bear in mind that there are probably a lot more resources available to service California for baseload than are generally recognized.

These are companies that have spent real money, tens of millions of dollars. There's probably $70-, $80-million been spent on geothermal projects that aren't producing now, not yet, because they missed the last market.

And then one point was made that we totally agree with, that we need to look at the import capability and determine what role renewables should play there. We would hope that baseload, of course, we're baseload guys, but we would hope that baseload would get a priority in terms of utilizing some of the import capacity to service California. That transmission is very valuable and intermittents don't make full use of the transmission capability.

We can't help but note that the ISO is having problems with 2000 megawatts of wind, average annual capacity may be 700 megawatts. And that's got to be a sobering aspect that I would hope that the ISO would be further involved in the process. And with baseload to help us know what they're faced with over there.

And you mentioned earlier that you'd like to see more staff, Commissioner, go to SCE. We'd like to see more staff go to the ISO. There's a heck of a backlog over there. And we would certainly like to see everybody get together and help the ISO.

Final point. Again, help deal with this under the question of future planning. We know that, of course, there's consideration of RECs, making RECs available, trading credits. It's a hot planning discussion now.

We can only comment on what we've personally observed in New Mexico. Our company helped get that 10 percent RPS law passed down there. We had good small geothermal projects. Our company and others had biomass projects that would have saved the Lincoln National Forest by doing thinning that was really needed.

And what happened is that 200 megawatt wind project that was discussed earlier today ruined the market for baseload renewables in New Mexico. And RECs were sold by PNM to another utility, and no baseload projects were selected. So there's a national forest, the Smokey Bear National Forest, the Lincoln National Forest are both suffering because of RECs transfer in California and the big wind project soaked up the whole market.

So I appreciate this ability to address you and look forward to the geothermal meetings. Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Steve. And I'd ask the staff to docket the written materials that Vulcan submitted into the docket, as well.

As I think everybody in the room knows, the renewable portfolio standard puts the question of technology choice and baseload versus peaking versus energy resources squarely in the laps of the utilities under the procurement process. The least cost/best fit criterion effectively allows each of the investor-owned utilities participating in the program to determine what types of renewable resources will best fit into, and most economically fit into their systems.

We may have the occasion to comment on that in our report later this year, as a matter of policy. But the initial rounds, and quite possibly subsequent rounds, as well, of the RPS solicitation really puts that question squarely in the laps of the utilities.

Part of the charm, if you will, of the RPS process is that Commissioner Pfannenstiel, Commissioner Boyd and I have no idea whatsoever what projects have been bid or where the bids have come in. We hope to learn that later down the road. And I'm sure at some point that process will come to an end and we'll all know that.

I would say the same thing about the Edison Company's interim solicitation, which I think this week went into month number 20 of contemplation. But right now it's a black box from the standpoint of my colleagues and myself. We don't know what's being bid, we don't know what prices are being bid. After we do we may have a chance to reflect on some of the comments that you've made.

MR. MILLER: My name's Mauri Miller.

I'm here on behalf of California Wind Energy Association, also, with Nancy. And my comments will, in fact, be brief, about a minute, I think.

I think the list of issues is a good list. I think it's much more difficult to say something's missing than it is to say something that's there is a reasonable issue. And I second Jim's comments about the way the issues are presented being our difficulty with the issues.

I have the benefit of about 20 years or 25 years now in the wind energy industry. And I came up at a time when the economics of wind were not good, and therefore we were fighting ourselves into the system through subsidies and through other methods of getting there.

We now are in the position where the economics of wind, I think, are very good. And we predicted 20 years ago, and I think rightly, that there will be institutional barriers to being accepted into the grid and accepted into the system.

I read the report coming into this meeting, and I've been here and I'm pleased to say that the meeting today seems positive and seems that people are looking for solutions rather than looking for problems. However, the report that was given to us was one that is -- looked like it was looking for problems, perhaps.

And I think that my comment is more don't let the history of the wind industry be the guide to solving the problems for the future. That there has been a lot of history in California. Perhaps New York and Idaho and Colorado and New Mexico have an advantage in that they don't have 20 years of history, and therefore they can look prospectively much more easily than perhaps the utilities in California.

I want to remind everyone that the economics of wind as a renewable probably are superior, without knowing the results of the solicitations, of course, to any other technology. And therefore we should be looking for solutions for integrating wind in.

And that the collaborative process for amendment 42 of the ISO tariff was one that was very cooperative, very much looking forward. And I think that everyone achieved a result that was acceptable to the wind industry, acceptable to the California ISO, acceptable to the utilities.

And I think that that type of

collaborative process can be utilized in most of these issues in front of us if we get the right experts in, and we get solutions that are both consistent with the technology that exists, consistent with the resource being not necessarily controllable. And consistent with the grid.

So, I want to hopefully turn this into a positive looking for solutions, rather than a method of those that may have a history, especially in California, to take a technology that is now becoming much more cost effective and finding yet other ways to slow the process down.

That's all. Thank you.

MR. ETO: Okay.

MS. TURNBULL: Good afternoon. I'm Jane Turnbull from the League of Women Voters of California. And I only have a question today that I can't answer that has been raised to us. And the question has to do with the potential for pump storage in the California Water Project.

And it has been brought to our attention that there appears to be considerable potential there that really has not been developed. And so I guess I'd like very much to hear from the staff in terms of whether that potential is real.

PRESIDING MEMBER GEESMAN: That's a question that came up several times in our workshop I think the week before last of integrating water and energy concerns. And it's something that we're taking a careful look at.

We've expanded the question to address not simply the existing State Water Project, as currently configured, but taking a look at the various off-stream storage proposals and other elements of the CalFed program that might lend themselves to better storage opportunities.

So it is one of the things that we expect to place some focus on in this cycle of the Integrated Energy Policy Report.

MS. TURNBULL: Okay, that sounds exciting.

MR. ETO: Did I miss anybody on this side of the room?

MS. ALLMAN: Hi, I'm Ellen Allman with Caithness Energy. And we have a lot of different technologies in our portfolio, but today I'm speaking on behalf of geothermal and I'm also speaking on behalf of Ormat (phonetic), Dan (inaudible) couldn't be here.

For the record we just respectfully take some exception to the statements that were made regarding geothermal. I realize it's a draft report, and I'm very thankful that there's a workshop coming up. But I just wanted to mention that Caithness and Ormat, and I'm sure Calpine and CalEnergy, would be very happy on a go-forward basis to participate in this process. Heretofore we hadn't been contacted.

So, again, thanks very much for having the opportunity to have a special workshop for geothermal.

PRESIDING MEMBER GEESMAN: We look forward to your involvement in that one.

MR. ETO: All right, Yuri, you wanted to make another comment?

MR. MAKAROV: I would like to make a very brief comment actually first about the role of the California ISO and the data collection process for renewable portfolio standard.

I just wanted to correct the impression which Nancy made by saying that we are not providing the data. We have provided three years of data, one-minute data. A lot of work was done on that, and it's not just right that we're not providing the data. The data quality issue is another matter.

The next point is about the storage devices. We started a project funded by the California Energy Commission which is actually about building a prototype flywheel storage device in our system, and use the storage device for regulation purposes. So it's quite an exciting project. So the pump storage is not the only option.

Thank you.

PRESIDING MEMBER GEESMAN: The Commission's PIER program, in coordination with DOE, conducted a solicitation I think about a year and a half ago to fund a portfolio of storage projects. We'll see where those lead.

I personally have been disappointed at the quality of projects that have turned up, both in our program and in the DOE program in this area. I think it's an area ripe for quite a bit of additional work. But thus far, I think the potential greatly exceeds what we've seen.

MR. ETO: Okay, let me turn it back to Don for next steps.

MR. KONDOLEON: Okay, before we speak of next steps, let me once again thank those of you in the audience. It really was an overwhelming response today. At one time I looked around and it seemed like virtually every seat was taken in the audience. And that's very reassuring to those of us who are charged with putting on these sorts of events, that at least we're in the right ballpark with regard to engaging the right folks.

I'm a transmission guy, not a renewables person, so I'm trying to cross the line here. And through the help of our folks who are very strong in the renewables area, like George Simons and others, have been very helpful identifying what people and who we need to engage in this whole process.

So, once again, I just want to thank you very much for participating today. And we look forward to your continued engagement with us as we move through the process.

And as Commissioner Geesman said at the outset, we're not going to solve all the problems in this IEPR cycle, and that's not our intent. It's to vet the issues, give you a forum for presenting your ideas, and trying to establish a trend of making progress here.

And it's not going to end when this

cycle cuts out. From a staff perspective, we'll have our draft documents hopefully by the end of July. But, you know, we look forward to continuing this with workshops probably throughout the end of the this calendar year and even into next year. That seems to be the way the transmission program moves these days.

So there's never an end for us, and as I said, we'll look forward to your continued participation.

Let me quickly highlight what we're doing with regard to the next steps. We've identified the fact that we'd like written comments on the material that was posted already on the website, any of the presentations and comments you've heard from other folks today.

We want to establish the record. It's important for us to have a written record from which the Committee can then rely on in producing the final policy document. So we encourage you to give us written comments, if possible by February 15th.

However, at the same time, Jim Dyer and the EPG folks have gone out and had personal contacts with a number of individual stakeholders and stakeholder groups and I think they would welcome the opportunity if there are other folks who felt that they haven't had an opportunity to speak to EPG and feel like they want to do that, somewhere in the pretty immediate timeframe, please contact me.

My contact information is on the workshop notice, which is posted. And I'll work as the intermediary to insuring that, you know, either a meeting can be set up with EPG, or at a minimum, a phone conversation. But we are trying to engage as many folks as we can.

And, again, there may be some confusion because we've tended to focus more on the wind area, at least from this side of the process. But, as I said, we will be working with George Simons and the PIER renewables folks to develop a separate workshop for the geothermal area. And we'll be notifying the stakeholders of that here in the near future. I'd again anticipate that to take place sometime in April.

In the meantime, as far as we are here, we will be summarizing and quantifying operational issues as sort of the next phase of this activity. We're going to review and develop policy options.

And I would anticipate that there will be a, let's call it an update or a status document that will be released prior to the next workshop. And we're looking at the next workshop sometime in the latter portion of April. I'll be working the next couple of weeks with the Committee to identify that date, and we'll let you know as quickly as we can.

But I anticipate again that we will have some sort of background updated status piece that you'll be able to look at in advance of the next workshop.

And then finally we will have a report that will summarize the findings that we had from this workshop and the findings from the next workshop. And, again, we'll have a comment period at the end of, you know, probably going through the middle of May that will allow you to comment on whatever is presented at the next workshop.

And then EPG will put together a piece for us, and that document will be appended to the staff's whitepaper. And the staff whitepaper will be covering this topic and a number of other transmission-related topics.

Currently we're targeting the latter

part of July for that document to be released. And there will probably be a workshop sometime in August to talk about the findings.

That's where we are with regard to the next steps. Are there any questions from the audience? And if not, let me turn it back over to Commissioner Geesman for any final remarks that he might have, or anyone else on the dais.

PRESIDING MEMBER GEESMAN: Thank you all for participating. We'll be adjourned.

(Whereupon, at 12:20 p.m., the workshop was adjourned.)

--o0o--

CERTIFICATE OF REPORTER

I, CHRISTOPHER LOVERRO, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 14thy day of February, 2005.